NEW SOURCE CONSTRUCTION PERMIT
Prevention of Significant Deterioration (PSD) Permit
Office of Air Quality

PSEG Lawrenceburg Energy Facility
582 West Eads Parkway
Lawrenceburg, IN 47025

(herein known as the Permittee) is hereby authorized to construct and operate subject to the conditions contained herein, the emission units described in Section A (Source Summary) of this permit.

This permit is issued to the above mentioned company under the provisions of 326 IAC 2-1.1, 326 IAC 2-5.1, 326 IAC 2-6.1 and 40 CFR 52.780, with conditions listed on the attached pages.

This permit is also issued under the provisions of 326 IAC 2-2, 40 CFR 52.21, and 40 CFR 52.124 (Prevention of Significant Deterioration), with conditions listed on the attached pages.

Construction Permit No.: CP 029-12517-00033	
Original signed by Paul Dubenetzky Issued by: Paul Dubenetzky, Branch Chief Office of Air Quality	Issuance Date: June 7, 2001

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SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.3 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-5.1-3(c)] [326 IAC 2-6.1-4(a)]

The Permittee owns and operates a natural gas merchant power plant.

Authorized Individual:	Benjamin Sisson
Source Address:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
Mailing Address:	PSEG Power LLC, 80 Park Plaza, 16th Floor, Newark, NJ 07102
Phone Number:	(973)-430-7597
SIC Code:	4911
County Location:	Dearborn
County Status:	Attainment for all Criteria Pollutants
Source Status:	Major, under PSD rules

A.2 Emissions units and Pollution Control Equipment Summary

This stationary source is approved to construct and operate the following emissions units and pollution control devices:

(a) Four (4) natural gas-fired combustion turbine generators, designated as units CT1, CT2, CT3, CT4, with a maximum heat input capacity of 1906.4 MMBtu/hr (per unit on a higher heating value), and exhausts to stacks designated as S1, S2, S3, S4, respectively.

(b) Four (4) heat recovery steam generators, designated as units HRSG1, HRSG2, HRSG3, HRSG4 with duct burners, and a maximum rate heat input capacity of 310 MMBtu/hr (per unit on a higher heating value), exhausting to stacks designated as S1, S2, S3, and S4, respectively.

(c) Four (4) selective catalytic reduction systems, designated as units SCR11, SCR12, SCR21, SCR22.

(d) Two (2) steam turbines, designated as units ST1 and ST2.

(e) Two (2) cooling towers, designated as units Cooling Tower 1 and Cooling Tower 2, exhausting to stacks designated S6 and S7, respectively.

(f) One (1) natural gas fired auxiliary boiler, designated Auxiliary Boiler, with a maximum heat input capacity of 124.6 MMBtu/hr (higher heating value), and exhausting to stack S5.

(g) One (1) diesel fire pump, with a rated capacity of 265 horsepower (hp), exhausting to stack S9.

(h) One (1) diesel backup electric generator, with a rated capacity of 1000 kilowatts (KW), exhausting to stack S8.

A.3 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3);

(c) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

A.4 Acid Rain Permit Applicability [326 IAC 2-7-2]

This stationary source shall be required to have a Phase II, Acid Rain permit by 40 CFR 72.30 (Applicability) because:

(a) The combustion turbines are new units under 40 CFR 72.6.

(b) The source cannot operate the combustion units until their Phase II, Acid Rain permit has been issued.

SECTION B GENERAL CONSTRUCTION CONDITIONS

THIS SECTION OF THE PERMIT IS BEING ISSUED UNDER THE PROVISIONS OF 326 IAC 2-1.1 AND 40 CFR 52.780, WITH CONDITIONS LISTED BELOW.

B.1 Permit No Defense [IC 13]

This permit to construct does not relieve the Permittee of the responsibility to comply with the provisions of the Indiana Environmental Management Law (IC 13-11 through 13-20; 13-22 through 13-25; and 13-30), the Air Pollution Control Law (IC 13-17) and the rules promulgated thereunder, as well as other applicable local, state, and federal requirements.

B.2 Definitions

Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, any applicable definitions found in IC 13-11, 326 IAC 1-2, and 326 IAC 2-1.1-1 shall prevail.

B.3 Effective Date of the Permit [40 CFR 124]

Pursuant to 40 CFR 124.15, 40 CFR 124.19, and 40 CFR 124.20, this permit is effective immediately after the service of notice of the decision, except as provided in 40 CFR 124.

B.4 Revocation of Permits [326 IAC 2-2-8]

Pursuant to 326 IAC 2-2-8(a)(1) and 40 CFR 52.21, this permit to construct shall expire if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is discontinued for a period of eighteen (18) months or more.

B.5 First Time Operation Permit [326 IAC 2-6.1]

This document shall also become a first time operating permit pursuant to 326 IAC 2-5.1-3 when, prior to start of operation, the following requirements are met:

(a) Any modifications required by 326 IAC 2-1.1 and 326 IAC 2-7-10.5 as a result of a change in the design or operation of emissions units described by this permit have been obtained prior to obtaining an Operation Permit Validation Letter.

(b) The attached Affidavit of Construction shall be submitted to the Office of Air Quality (OAQ), Permit Administration & Development Section.

(1) If the Affidavit of Construction verifies that the facilities covered in this Construction Permit were constructed as proposed in the application, then the facilities may begin operating on the date the Affidavit of Construction is postmarked or hand delivered to IDEM.

(2) If the Affidavit of Construction does not verify that the facilities covered in this Construction Permit were constructed as proposed in the application, then the Permittee shall receive an Operation Permit Validation Letter from the Chief of the Permit Administration & Development Section prior to beginning operation of the facilities.

(c) If construction is completed in phases; i.e., the entire construction is not done continuously, a separate affidavit must be submitted for each phase of construction. Any permit conditions associated with operation start up dates such as stack testing for New Source Performance Standards (NSPS) shall be applicable to each individual phase.

(d) Upon receipt of the Operation Permit Validation Letter from the Chief of the Permit Administration & Development Section, the Permittee shall attach it to this document.

(e) The operation permit will be subject to annual operating permit fees pursuant to 326 IAC 2-7-19 (Fees).

(f) Pursuant to 326 IAC 2-7-4(a)(1)(A)(ii) and 326 IAC 2-5.1-4, the Permittee shall apply for a Title V operating permit within twelve (12) months of the date on which the source first meets an applicability criterion of 326 IAC 2-7-2.

B.6 NSPS Reporting Requirement

Pursuant to the New Source Performance Standards (NSPS), Part 60.7, Part 60.8, the source owner/operator is hereby advised of the requirement to report the following at the appropriate times:

(a) Commencement of construction date (no later than 30 days after such date);

(b) Anticipated start-up date (not more than 60 days or less than 30 days prior to such date);

(c) Actual start-up date (within 15 days after such date); and

(d) Date of performance testing (at least 30 days prior to such date), when required by a condition elsewhere in this permit.

Reports are to be sent to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue P.O. Box 6015
Indianapolis, IN 46206-6015

The application and enforcement of these standards have been delegated to the IDEM, OAQ. The requirements of 40 CFR Part 60 are also federally enforceable.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

C.1 Major Source

Pursuant to 326 IAC 2-2 (Prevention of Significant Deterioration) and 40 CFR 52.21, and 326 IAC 2-7 (Part 70 Permit Program) this source is a major source.

C.2 Preventive Maintenance Plan [326 IAC 1-6-3]

(a) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMP) ninety (90) days after the commencement of normal operations after the first construction phase, including the following information on each emissions unit:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions;

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

(b) The Permittee shall implement the Preventive Maintenance Plans as necessary to ensure that failure to implement the Preventive Maintenance Plan does not cause or contribute to a violation of any limitation on emissions or potential to emit.

(c) PMP's shall be submitted to IDEM, OAQ upon request and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its Preventive Maintenance Plan whenever lack of proper maintenance causes or contributes to any violation.

C.3 Source Modification [326 IAC 2-7-10.5]

(a) The Permittee must comply with the requirements of 326 IAC 2-7-10.5 whenever the Permittee seeks to construct new emissions units, modify existing emissions units, or otherwise modify the source.

(b) Any application requesting an amendment or modification of this permit shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

Any such application should be certified by the "responsible official" as defined by 326 IAC 2-7-1(34) only if a certification is required by the terms of the applicable rule.

C.4 Inspection and Entry [326 IAC 2-5.1-3(e)(4)(B)] [326 IAC 2-6.1-5(a)(4)]

Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee’s right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a permitted source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under this title or the conditions of this permit or any operating permit revisions;

(c) Inspect, at reasonable times, any processes, emissions units (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit or any operating permit revisions;

(d) Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and

(e) Utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

C.5 Transfer of Ownership or Operation [326 IAC 2-6.1-6(d)(3)]

Pursuant to [326 IAC 2-6.1-6(d)(3)]

(a) In the event that ownership of this source is changed, the Permittee shall notify IDEM, OAQ, Permits Branch, within thirty (30) days of the change.

(b) The written notification shall be sufficient to transfer the permit to the new owner by a notice-only change pursuant to 326 IAC 2-6.1-6(d)(3).

(c) IDEM, OAQ shall issue a revised permit.

The notification which shall be submitted by the Permittee does require the certification by the “authorized individual” as defined by 326 IAC 2-1.1-1.

C.6 Permit Revocation [326 IAC 2-1-9]

Pursuant to 326 IAC 2-1-9(a)(Revocation of Permits), this permit to construct and operate may be revoked for any of the following causes:

(a) Violation of any conditions of this permit.

(b) Failure to disclose all the relevant facts, or misrepresentation in obtaining this permit.

(c) Changes in regulatory requirements that mandate either a temporary or permanent reduction of discharge of contaminants. However, the amendment of appropriate sections of this permit shall not require revocation of this permit.

(d) Noncompliance with orders issued pursuant to 326 IAC 1-5 (Episode Alert Levels) to reduce emissions during an air pollution episode.

(e) For any cause which establishes in the judgment of IDEM, the fact that continuance of this permit is not consistent with purposes of this article.

C.7 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes, sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute non-overlapping integrated averages for a continuous opacity) monitor in a six (6) hour period.

C.8 Fugitive Dust Emissions [326 IAC 6-4]

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

C.9 Stack Height [326 IAC 1-7]

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted by using good engineering practices (GEP) pursuant to 326 IAC 1-7-3.

Testing Requirements

C.10 Performance Testing [326 IAC 3-6]

(a) Compliance testing on new emissions units shall be conducted within 60 days after achieving maximum production rate, but no later than180 days after initial start-up, if specified in Section D of this approval. All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this permit, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ.

A test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

no later than thirty-five (35) days prior to the intended test date. The Permittee shall submit a notice of the actual test date to the above address so that it is received at least two weeks prior to the test date.

(b) IDEM, OAQ must receive all test reports within forty-five (45) days after the completion of the testing. IDEM, OAQ may grant an extension, if the source submits to IDEM, OAQ, a reasonable written explanation within five (5) days prior to the end of the initial forty-five (45) day period.

The documentation submitted by the Permittee does not require certification by the "authorized individual" as defined by 326 IAC 2-1.1-1.

Compliance Monitoring Requirements

C.11 Compliance Monitoring [326 IAC 2-1.1-11]

Compliance with applicable requirements shall be documented as required by this permit. The Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. All monitoring and record keeping requirements not already legally required shall be implemented when operation begins.

C.12 Maintenance of Monitoring Equipment [IC 13-14-1-13]

(a) In the event that a breakdown of the monitoring equipment occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem. To the extent practicable, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less frequent than required in Section D of this permit until such time as the monitoring equipment is back in operation. In the case of continuous monitoring, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less than one (1) hour until such time as the continuous monitor is back in operation.

(b) The Permittee shall install, calibrate, quality assure, maintain, and operate all necessary monitors and related equipment. In addition, prompt corrective action shall be initiated whenever indicated.

C.13 Monitoring Methods [326 IAC 3]

Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60, Appendix A, or other approved methods as specified in this permit.

C.14 Compliance Monitoring Plan - Failure to Take Response Steps [326 IAC 1-6] [326 IAC 2-2-4]

(a) The Permittee is required to implement a compliance monitoring plan to ensure that reasonable information is available to evaluate its continuous compliance with applicable requirements. This compliance monitoring plan is comprised of:

(1) This condition;

(2) The Compliance Determination Requirements in Section D of this permit;

(3) The Compliance Monitoring Requirements in Section D of this permit;

(4) The Record Keeping and Reporting Requirements in Section C (Monitoring Data Availability, General Record Keeping Requirements, and General Reporting Requirements) and in Section D of this permit; and

(5) A Compliance Response Plan (CRP) for each compliance monitoring condition of this permit. CRP's shall be submitted to IDEM, OAQ upon request and shall be subject to review and approval by IDEM, OAQ. The CRP shall be prepared within ninety (90) days after the commencement of normal operation after the first phase of construction and shall be maintained on site, and is comprised of:

(A) Response steps that will be implemented in the event that compliance related information indicates that a response step is needed pursuant to the requirements of Section D of this permit; and

(B) A time schedule for taking such response steps including a schedule for devising additional response steps for situations that may not have been predicted.

(b) For each compliance monitoring condition of this permit, appropriate response steps shall be taken when indicated by the provisions of that compliance monitoring condition. Failure to perform the actions detailed in the compliance monitoring conditions or failure to take the response steps within the time prescribed in the Compliance Response Plan, shall constitute a violation of the permit unless taking the response steps set forth in the Compliance Response Plan would be unreasonable.

(c) After investigating the reason for the excursion, the Permittee is excused from taking further response steps for any of the following reasons:

(1) The monitoring equipment malfunctioned, giving a false reading. This shall be an excuse from taking further response steps providing that prompt action was taken to correct the monitoring equipment.

(2) The Permittee has determined that the compliance monitoring parameters established in the permit conditions are technically inappropriate, has previously submitted a request for an administrative amendment to the permit, and such request has not been denied or;

(3) An automatic measurement was taken when the process was not operating; or

(4) The process has already returned to operating within "normal" parameters and no response steps are required.

(d) Records shall be kept of all instances in which the compliance related information was not met and of all response steps taken.

C.15 Actions Related to Noncompliance Demonstrated by a Stack Test

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall take appropriate corrective actions. The Permittee shall submit a description of these corrective actions to IDEM, OAQ within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize emissions from the affected emissions unit while the corrective actions are being implemented. IDEM, OAQ shall notify the Permittee within thirty (30) days, if the corrective actions taken are deficient. The Permittee shall submit a description of additional corrective actions taken to IDEM, OAQ within thirty (30) days of receipt of the notice of deficiency. IDEM, OAQ reserve the authority to use enforcement activities to resolve noncompliant stack tests.

(b) A retest to demonstrate compliance shall be performed within one hundred twenty (120) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred and twenty (120) days is not practicable, IDEM, OAQ may extend the retesting deadline. Failure of the second test to demonstrate compliance with the appropriate permit conditions may be grounds for immediate revocation of the permit to operate the affected emissions unit.

The documents submitted pursuant to this condition do not require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1.

Record Keeping and Reporting Requirements

C.16 Malfunctions Report [326 IAC 1-6-2]

Pursuant to 326 IAC 1-6-2 (Records; Notice of Malfunction):

(a) A record of all malfunctions, including startups or shutdowns of any facility or emission control equipment, which result in violations of applicable air pollution control regulations or applicable emission limitations shall be kept and retained for a period of three (3) years and shall be made available to the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ), or appointed representative upon request.

(b) When a malfunction of any facility or emission control equipment occurs which lasts more than one (1) hour, said condition shall be reported to OAQ, using the Malfunction Report Forms (2 pages). Notification shall be made by telephone or facsimile, as soon as practicable, but in no event later than four (4) daytime business hours after the beginning of said occurrence.

(c) Failure to report a malfunction of any emission control equipment shall constitute a violation of 326 IAC 1-6, and any other applicable rules. Information of the scope and expected duration of the malfunction shall be provided, including the items specified in 326 IAC 1-6-2(a)(1) through (6).

(d) Malfunction is defined as any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner. [326 IAC 1-2-39]

C.17 Monitoring Data Availability [326 IAC 2-6.1-2] [IC 13-14-1-13]

(a) With the exception of performance tests conducted in accordance with Section C-Performance Testing, all observations, sampling, maintenance procedures, and record keeping, required as a condition of this permit shall be performed at all times the equipment is operating at normal representative conditions.

(b) As an alternative to the observations, sampling, maintenance procedures, and record keeping of subsection (a) above, when the equipment listed in Section D of this permit is not operating, the Permittee shall either record the fact that the equipment is shut down or perform the observations, sampling, maintenance procedures, and record keeping that would otherwise be required by this permit.

(c) If the equipment is operating but abnormal conditions prevail, additional observations and sampling should be taken with a record made of the nature of the abnormality.

(d) If for reasons beyond its control, the operator fails to make required observations, sampling, maintenance procedures, or record keeping, reasons for this must be recorded.

(e) At its discretion, IDEM may excuse such failure providing adequate justification is documented and such failures do not exceed five percent (5%) of the operating time in any quarter.

(f) Temporary, unscheduled unavailability of staff qualified to perform the required observations, sampling, maintenance procedures, or record keeping shall be considered a valid reason for failure to perform the requirements stated in (a) above.

C.18 General Record Keeping Requirements [326 IAC 2-6.1-2]

(a) Records of all required monitoring data and support information shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. These records shall be kept at the source location for a minimum of three (3) years and available upon the request of an IDEM, OAQ representative. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a written request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Records of required monitoring information shall include, where applicable:

(1) The date, place, and time of sampling or measurements;

(2) The dates analyses were performed;

(3) The company or entity performing the analyses;

(4) The analytic techniques or methods used;

(5) The results of such analyses; and

(6) The operating conditions existing at the time of sampling or measurement.

(c) Support information shall include, where applicable:

(1) Copies of all reports required by this permit;

(2) All original strip chart recordings for continuous monitoring instrumentation;

(3) All calibration and maintenance records;

(4) Records of preventive maintenance shall be sufficient to demonstrate that failure to implement the Preventive Maintenance Plan did not cause or contribute to a violation of any limitation on emissions or potential to emit. To be relied upon subsequent to any such violation, these records may include, but are not limited to: work orders, parts inventories, and operator's standard operating procedures. Records of response steps taken shall indicate whether the response steps were performed in accordance with the Compliance Response Plan required by Section C - Compliance Monitoring Plan - Failure to take Response Steps, of this permit, and whether a deviation from a permit condition was reported. All records shall briefly describe what maintenance and response steps were taken and indicate who performed the tasks.

(d) All record keeping requirements not already legally required shall be implemented when operation begins.

C.19 General Reporting Requirements [326 IAC 2-1.1-11] [326 IAC 2-6.1-2] [IC 13-14-1-13]

(a) To affirm that the source has met all the compliance monitoring requirements stated in this permit the source shall submit a Semi-annual Compliance Monitoring Report. Any deviation from the requirements and the date(s) of each deviation must be reported. The Compliance Monitoring Report shall include the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(b) The report required in (a) of this condition and reports required by conditions in Section D of this permit shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(d) Unless otherwise specified in this permit, any semi-annual report shall be submitted within thirty (30) days of the end of the reporting period. The reports require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(e) All instances of deviations must be clearly identified in such reports. A reportable deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit or a rule. It does not include:

(1) An excursion from compliance monitoring parameters as identified in Section D of this permit unless tied to an applicable rule or limit; or

(2) A malfunction as described in 326 IAC 1-6-2; or

(3) Failure to implement elements of the Preventive Maintenance Plan unless lack of maintenance has caused or contributed to a deviation.

(4) Failure to make or record information required by the compliance monitoring provisions of Section D unless such failure exceeds 5% of the required data in any calendar quarter.

A Permittee's failure to take the appropriate response step when an excursion of a compliance monitoring parameter has occurred or failure to monitor or record the required compliance monitoring is a deviation.

(f) Any corrective actions or response steps taken as a result of each deviation must be clearly identified in such reports.

(g) The first report shall cover the period commencing on the date start of normal operation after the first phase of construction and ending on the last day of the reporting period.

SECTION D.1 FACILITY CONDITIONS – Combined Cycle Operation

(a) Four (4) natural gas-fired combustion turbine generators, designated as units CT1, CT2, CT3, CT4, with a maximum heat input capacity of 1906.4 MMBtu/hr (per unit on a higher heating value), and exhausts to stacks designated as S1, S2, S3, S4, respectively.

(b) Four (4) heat recovery steam generators, designated as units HRSG1, HRSG2, HRSG3, HRSG4 with duct burners, and a maximum rate heat input capacity of 310 MMBtu/hr (per unit on a higher heating value), exhausting to stacks designated as S1, S2, S3, and S4, respectively.

(c) Four (4) selective catalytic reduction systems, designated as units SCR11, SCR12, SCR21, SCR22.

(d) Two (2) steam turbines, designated as units ST1 and ST2.

(e) Two (2) cooling towers, designated as units Cooling Tower 1 and Cooling Tower 2, exhausting to stacks designated S6 and S7, respectively.

(The information describing the process contained in this facility description box is descriptive information, and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.1.1 Prevention of Significant Deterioration [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD), this new source is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of PM, PM_{10}, SO_2, CO, NO_X, and VOC because the potential to emit for these pollutants exceed the PSD major significant thresholds. Therefore, the PSD provisions require that this new source be reviewed to ensure compliance with the National Ambient Air Quality Standards (NAAQS), the applicable PSD air quality increments, and the requirements to apply the Best Available Control Technology (BACT) for the affected pollutants.

D.1.2 Particulate Matter (PM/PM_{10}) Emission Limitations for Combustion Turbines/Duct Burners

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), the total PM, which is the sum of PM (filterable) and PM_{10} (filterable and condensible), emissions from each combustion turbine shall not exceed twenty one (21) pounds per hour for each combustion turbine, during normal operation normal operation (fifty (50) percent load or more).

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the total PM, which is the sum of PM (filterable) and PM_{10} (filterable and condensible), emissions from each combustion turbine when its associated duct burner is operating, shall not exceed 24.10 pounds per hour for each combustion turbine and duct burner.

D.1.3 Opacity Limitations

Pursuant to 326 IAC 2-2 (PSD Requirements) the opacity from each associated combustion turbine stack shall not exceed twenty (20) percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent. The opacity standards apply at all times, except during periods of startup, shutdown or malfunction. This satisfies the opacity limitations required by 326 IAC 5-1 (Opacity Limitations).

D.1.4 Particulate Matter Emissions (PM/PM_{10}) for Cooling Towers

Pursuant to 326 IAC 2-2 (PSD Requirements) each cooling tower shall comply with the following:

(1) PM, which is the sum of PM (filterable) and PM_{10} (filterable and condensible), emissions shall not exceed 0.876 pounds per hour, and

(2) Employ good design and operation practices to limit emissions from the cooling towers.

D.1.5 Startup and Shutdown Limitations for Combustion Turbines

Pursuant to 326 IAC 2-2 (PSD Requirements), a startup or shutdown is defined as less than fifty (50) percent load. Each combustion turbine generating unit shall comply with the following:

(a) A startup or shutdown period shall not exceed 3.5 hours. Each turbine shall not exceed 560 hours per year for startups and shutdowns.

(b) During periods of startup and shutdown good combustion practice shall be used to limit NO_X and CO emissions.

(c) The NO_X and CO emissions during startup and shutdown periods shall be monitored.

(d) The startup and shutdown data for the first thirty-six (36) months of operation shall be submitted to the OAQ Permits Branch in order to evaluate and establish a short-term limit (pounds per startup and pounds per shutdown) during periods of startup and shutdown. The short-term limit shall consider, but will not be limited to, performance degradation of the combustion turbine up to the first major overhaul. The startup and shutdown data shall be submitted within 90 days after the 36-month monitoring period.

D.1.6 Nitrogen Oxides (NO_X) Emission Limitations for Combustion Turbines/Duct Burners

(a) Pursuant to 326 IAC 2-2 (PSD Requirements) each combustion turbine/steam generating unit shall comply with the following, excluding periods of startup and shutdown:

(1) During normal combined cycle operation (fifty (50) percent load or more), the NO_X emissions from each combustion turbine stack shall not exceed 3.0 ppmvd corrected to fifteen (15) percent oxygen, based on a three (3) hour averaging period, which is equivalent to 21.0 pounds per hour for each combustion turbine.

(2) During normal combined cycle operation (fifty (50) percent load or more), the NO_X emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 3.0 ppmvd corrected to fifteen (15) percent oxygen, based on a three (3) hour averaging period, which is equivalent to 24.41 pounds per hour for each combustion turbine and duct burner.

(3) The duct burners shall not be operated until the associated combustion turbine reaches base load.

(4) Each combustion turbine shall be equipped with dry low-NO_X burners and operated using good combustion practices to control NO_X emissions.

(5) A selective catalytic reduction (SCR) system shall be installed and operated at all times, except during periods of startup and shutdown, to control NO_X emissions.

(6) Use natural gas as the only fuel.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual NO_X emission from each of the four (4) combustion turbines and associated duct burners, excluding startup and shutdown periods, shall not exceed 78.1 tons per year.

D.1.7 Carbon Monoxide (CO) Emission Limitations for Combustion Turbines/Duct Burners

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), each steam generating unit shall comply with the following, excluding startup and shutdown emissions:

(1) During normal combined cycle operation (fifty (50) percent load or more), the CO emissions from each combustion turbine shall not exceed 6 ppmvd corrected to 15% O_2 on a 24 hour averaging period, which is equivalent to 21.3 pounds per hour for each combustion turbine.

(2) During normal operation (fifty (50) percent load of more), the CO emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 9 ppmvd corrected to 15% O_2 on a 24 hour averaging period, which is equivalent to 40.5 pounds per hour for each combustion turbine and duct burner.

(3) The duct burners shall not be operated until normal operation begins.

(4) Good combustion practices shall be applied to minimize CO emissions.

(5) Use natural gas as the only fuel.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual CO emission from each of the four (4) combustion turbines and associated duct burners, excluding startup and shutdown periods, shall not exceed 102.21 tons per year.

D.1.8 Sulfur Dioxide (SO_2) Emission Limitations for Combustion Turbines/Duct Burners

Pursuant to 326 IAC 2-2 (PSD Requirements), each combustion turbine and duct burner shall comply with the following, excluding startup and shutdown emissions:

(1) During normal combined cycle operation (fifty (50) percent load or more), the SO_2 emissions from each combustion turbine shall not exceed 11.0 pounds per hour for each combustion turbine.

(2) During normal combined cycle operation of each combustion turbine when its associated duct burner is operating, the SO_2 emissions from each turbine stack shall not exceed 12.71 pounds per hour.

(3) The use of low sulfur natural gas as the only fuel for the combustion turbines and duct burners. The sulfur content of the natural gas shall not exceed two (2) grains per 100 scf.

(4) Perform good combustion practice.

D.1.9 Volatile Organic Compound (VOC) Emission Limitations for Combustion Turbines/Duct Burners

Pursuant to 326 IAC 8-1-6 (VOC Requirements) and 326 2-2 (PSD Requirements), each combustion turbine and duct burner shall comply with the following, excluding startup and shutdown emissions:

(1) The VOC emissions from each combustion turbine shall not exceed 3.0 pounds VOC per hour for each combustion turbine.

(2) The VOC emissions from each combustion turbine stack, when its associated duct burner is operating shall not exceed 7.7 pounds VOC per hour.

(3) The use of natural gas as the only fuel.

(4) Good combustion practice shall be implemented to minimize VOC emissions.

D.1.10 40 CFR 60, Subpart GG (Stationary Gas Turbines)

The four (4) natural gas combustion turbines are subject to 40 CFR Part 60, Subpart GG (Stationary Gas Turbines) because the heat input at peak load is equal to or greater than 10.7 gigajoules per hour (10 MMBtu per hour), based on the lower heating value of the fuel fired.

Pursuant to 326 IAC 12-1 and 40 CFR 60, Subpart GG (Stationary Gas Turbines), the Permittee shall:

(1) Limit nitrogen oxides emissions from the natural gas turbines to 0.0113% by volume at 15% oxygen on a dry basis, as required by 40 CFR 60.332, to:

$$STD = 0.0075 \frac{(14.4)}{Y} + F,$$

where STD = allowable NO_x emissions (percent by volume at 15 percent oxygen on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

(2) Limit sulfur dioxide emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at 15 percent oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to 0.8 percent by weight;

D.1.11 40 CFR Part 60, Subpart Da (Electric Utility Steam Generating Units)

The four (4) heat recovery steam generator (HRSG) duct burners (DB) are subject to 40 CFR Part 60, Subpart Da because the heat input capacity is greater than 250 MMBtu/hr.

Pursuant to 40 CFR Part 60, Subpart Da, the Permittee shall:

(a) The opacity from each combustion turbine stack, when its associated duct burner is operating, shall not exceed twenty (20) percent (6-minute average), except for a 6-minute period per hour of not more than 27 percent. The opacity standards apply at all times, except during periods of startup, shutdown or malfunction. This satisfies the opacity limitations required by 326 IAC 5-1 (Opacity Limitations).

(b) The PM emissions from each duct burner shall not exceed 0.03 pounds per MMBtu heat input on a higher heating value basis.

(c) Each duct burner shall not exceed 1.6 lb/MW-hr NO_X on a thirty (30) day rolling average.

(d) Each duct burner shall not exceed 0.20 pounds SO_2 per MMBtu heat input, determined on a 30-day rolling average basis.

D.1.12 Formaldehyde Limitations

Pursuant to 326 IAC 2-1.1-5 (Air Quality Requirements), the formaldehyde emissions from each combustion turbine shall not exceed 0.00011 pounds of formaldehyde per MMBtu.

D.1.13 Ammonia Limitations

Pursuant to 326 IAC 2-1.1-5 (Air Quality Requirements), the ammonia emissions from each combustion turbine stack shall not exceed ten (10) ppmvd corrected to 15% O_2 on a 3 hour block average.

D.1.14 Preventive Maintenance Plan [326 IAC 1-6-3]

A Preventive Maintenance Plan, in accordance with Section C - Preventive Maintenance Plan, of this permit, is required for each combustion turbine and its control device.

Compliance Determination Requirements

D.1.15 Performance Testing

(a) Pursuant to 326 IAC 3-5 the Permittee shall conduct a performance test, no later than one-hundred and eighty days (180) after the facility startup or monitor installation, on the combustion turbine exhaust stack (S1, S2, S3, S4) in order to certify the continuous emission monitoring systems for NO_X and CO.

(b) Within one-hundred and eighty (180) days after initial startup, the Permittee shall perform formaldehyde stack test for each combustion turbine stack (S1, S2, S3, S4) utilizing a method approved by the Commissioner when operating at 60%, 75%, and 100% load. These tests shall be performed in accordance with Section C – Performance Testing, in order to verify the formaldehyde emission factor specified in Condition D.1.12.

(c) Within one-hundred and eighty (180) days after initial startup, the Permittee shall perform NO_X and CO stack tests for each combustion turbine stack (S1, S2, S3, S4) during a startup/shutdown period, utilizing a certified continuous emission monitoring system and a flue flow meter. These tests shall be performed in accordance with Section C – Performance Testing, in order to document compliance with Condition D.1.5.

(d) Within sixty (60) days of achieving maximum production rate, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall conduct NO_X and SO_2 stack tests for each combustion turbine stack (S1, S2, S3, S4) utilizing methods approved by the Commissioner. These tests shall be performed in accordance with 40 CFR 60.335 and Section C – Performance Testing, in order to document compliance with Condition D.1.10.

(e) Within one-hundred and eighty (180) days after initial startup, the Permittee shall perform PM, PM_{10} (filterable and condensible), VOC, and ammonia stack tests for each combustion turbine stack (1, 2, 3, 4) utilizing methods approved by the Commissioner. These tests shall be performed in accordance with 40 CFR 60.335, 40 CFR 60.48(a), and Section C – Performance Testing, in order to document compliance with D.1.2, D.1.9, and D.1.13.

(f) IDEM, OAQ retain the authority under 326 IAC 2-1-4(f) to require the Permittee to perform additional and future compliance testing as necessary.

D.1.16 40 CFR Part 60, Subpart GG Compliance Requirements (Stationary Gas Turbines)

Pursuant to 40 CFR Part 60, Subpart GG (Stationary Gas Turbines), the Permittee shall monitor the nitrogen and sulfur content of the natural gas on a monthly basis as follows:

(a) Determine compliance with the nitrogen oxide and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a), per requirements described in 40 CFR 60.335(c);

(b) Determine the sulfur content of the natural gas being fired in the turbine by ASTM Methods D 1072-80, D 3030-81, D 4084-82, or D 3246-81. The applicable ranges of some ASTM methods mentioned are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator; and

(c) Determine the nitrogen content of the natural gas being fired in the turbine by using analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator.

The analyses required above may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor or any other qualified agency.

Owners, operators or fuel vendors may develop custom fuel schedules for determination of the nitrogen and sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. These schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with the above requirements.

D.1.17 Continuous Emission Monitoring (CEMs)

(a) The owner or operator of a new source with an emission limitation or permit requirement established under 326 IAC 2-5.1-3 and 326 IAC 2-2, shall be required to install a continuous emissions monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5-1(d).

(b) The Permittee shall install, calibrate, certify, operate and maintain a continuous emission monitoring system for NO_X and CO, for stacks designated as S1, S2, S3, S4 in accordance with 326 IAC 3-5-2 and 3-5-3.

(1) The continuous emission monitoring system (CEMS) shall measure NO_X and CO emissions rates in pounds per hour and parts per million (ppmvd) corrected to 15%

O_2. The use of CEMS to measure and record the NO_X and CO hourly limits, is sufficient to demonstrate compliance with the limitations established in the BACT analysis and set forth in the permit. To demonstrate compliance with the NO_X limit, the source shall take an average of the parts per million (ppmvd) corrected to 15% O_2 over a three (3) hour averaging period. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppmvd) corrected to 15% O_2 over a twenty four (24) hour block averaging period. The source shall maintain records of the parts per million and the pounds per hour.

(2) The Permittee shall determine compliance with Condition D.1.5 utilizing data from the NO_X, CO, and O_2 CEMS, the fuel flow meter, and Method 19 calculations.

(3) The Permittee shall submit to IDEM, OAQ, within ninety (90) days after monitor installation, a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4.

(4) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7.

(c) Pursuant to 40 CFR 60.47(d), the Permittee shall install, calibrate, certify and operate continuous emissions monitors for carbon dioxide or oxygen at each location where nitrogen oxide emissions are monitored.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.1.18 Record Keeping Requirements

(a) To document compliance with Conditions D.1.2, D.1.6 through D.1.9, and D.1.12, the Permittee shall maintain records of the following:

(1) Amount of natural gas combusted (in MMSCF) per turbine during each month.

(2) Percent sulfur of the natural gas.

(3) Heat input on a higher heating value basis of each turbine on a 30-day rolling average.

(b) To document compliance with Condition D.1.5, the Permittee shall maintain records of the following:

(1) The type of operation (i.e. startup or shutdown) with supporting operational data.

(2) The total number of minutes for startup or shutdown per 24-hour averaging period per turbine.

(3) The CEMS data, fuel flow meter data, and Method 19 calculations corresponding to each startup and shutdown period.

(c) To document compliance with Conditions D.1.6 and D.1.7, the Permittee shall maintain records of the emission rates of NO_X and CO in pounds per hour and parts per million (ppmvd) at 15% oxygen.

(d) To document compliance with Condition D.1.17, the Permittee shall maintain records, including raw data of all monitoring data and supporting information, for a minimum of five (5) years from the date described in 326 IAC 3-5-7(a). The records shall include the information described in 326 IAC 3-5-7(b).

(e) To document compliance with D.1.10, the Permittee shall maintain records of the natural gas analyses, including the sulfur and nitrogen content of the gas, for a period of three (3) years.

(f) All records shall be maintained in accordance with Section C – General Record Keeping Requirements, of this permit.

D.1.19 Reporting Requirements

The Permittee shall submit the following information on a quarterly basis:

(a) Records of excess NO_X and CO emissions (defined in 326 IAC 3-5-7 and 40 CFR Part 60.7) from the continuous emissions monitoring system. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C – General Reporting Requirements of this permit.

(b) The Permittee shall report periods of excess emissions, as required by 40 CFR 60.334(c).

(c) A quarterly summary of the CEMs data to document compliance with D.1.6, and D.1.7 shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported.

(d) A quarterly summary of the total number of startup and shutdown hours of operation to document compliance with Condition D.1.5, shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported.

SECTION D.2 FACILITY CONDITIONS – Auxiliary Boiler

One (1) natural gas fired auxiliary boiler, designated Auxiliary Boiler, with a maximum heat input capacity of 124.6 MMBtu/hr (higher heating value), and exhausting to stack S5. (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.2.1 Prevention of Significant Deterioration [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD), this new source is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of PM, PM_{10}, SO_2, CO, NO_X, and VOC because the potential to emit for these pollutants exceed the PSD major significant thresholds. Therefore, the PSD provisions require that this new source be reviewed to ensure compliance with the National Ambient Air Quality Standards (NAAQS), the applicable PSD air quality increments, and the requirements to apply the Best Available Control Technology (BACT) for the affected pollutants.

D.2.2 Particulate Matter Emissions (PM/PM_{10}) for the Auxiliary Boiler

Pursuant to 326 IAC 2-2 (PSD Requirements) the auxiliary boiler shall comply with the following:

(a) PM and PM_{10} emissions from the auxiliary boiler shall not exceed 0.928 pounds per hour.

(b) Use natural gas as the only fuel for the auxiliary boiler.

(c) Perform good combustion practices.

D.2.3 Opacity Limitations

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(c) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(d) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes, sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute non-overlapping integrated averages for a continuous opacity) monitor in a six (6) hour period.

D.2.4 Nitrogen Oxide (NO_X) Emission Limitations for the Auxiliary Boiler

Pursuant to 326 IAC 2-2 (PSD Requirements), the auxiliary boiler shall comply with the following:

(a) NO_X emissions from the auxiliary boiler shall not exceed 0.036 lb/MMBtu on a higher heating value basis, which is equivalent to 4.49 pounds per hour.

(b) Use natural gas as the only fuel for the auxiliary boiler.

(c) Operate auxiliary boiler using low-NOx burners.

D.2.5 Carbon Monoxide (CO) Emission Limitations for the Auxiliary Boiler

Pursuant to 325 IAC 2-2 (PSD Requirements) the auxiliary boiler shall comply with the following:

(a) CO emissions from the auxiliary boiler shall not exceed 0.082 lb/MMBtu on a higher heating value basis, which is equivalent to 10.28 pounds per hour.

(b) Use natural gas as the only fuel for the auxiliary boiler.

(c) Operate utilizing good combustion practices.

D.2.6 Sulfur Dioxide (SO_2) Emission Limitations for the Auxiliary Boiler

Pursuant to 326 IAC 2-2 (PSD Requirements) the auxiliary boiler shall comply with the following:

(a) SO_2 emissions from the auxiliary boiler shall not exceed 0.006 lb/MMBtu on a higher heating value basis, which is equivalent to 0. 70 pounds per hour.

(b) Use natural gas, with a sulfur content of less than or equal to 0.8 percent by weight, as the only fuel for the auxiliary boiler.

(c) Operate utilizing good combustion practices.

D.2.7 Volatile Organic Compound (VOC) Emission Limitations for the Auxiliary Boiler

Pursuant to 326 IAC 2-2 (PSD Requirements) and 326 IAC8-1-6 (General Reduction Requirements) the auxiliary boiler shall comply with the following:

(a) VOC emissions from the auxiliary boiler shall not exceed 0.0054 lb/MMBtu on a higher heating value basis, which is equivalent to 0.672 pounds per hour.

(b) Use natural gas as the only fuel for the auxiliary boiler.

(c) Operate using good combustion practices.

D.2.8 40 CFR Part 60, Subpart Db (Industrial Steam Generating Units)

The auxiliary boiler is subject to the requirements of 40 CFR Part 60, Subpart Db because the heat input capacity of the boiler is greater than 100 MMBtu/hr. Pursuant to 40 CFR Part 60, Subpart Db, the NO_X emission from the natural gas fired boiler shall not exceed 0.2 lb/MMBtu on a 30-day rolling average.

D.2.9 Natural Gas Limitations

Pursuant to 326 IAC 2-2 (PSD Requirements), the natural gas usage from the auxiliary boiler shall not exceed 122.2 MMscf per year per year, based on a twelve (12) consecutive month period.

D.2.10 Preventive Maintenance Plan [326 IAC 1-6-3]

A Preventive Maintenance Plan must be prepared, in accordance with Section C - Preventive Maintenance Plan, of this permit.

Compliance Determination Requirements

D.2.11 Performance Testing

Pursuant to 326 IAC 2-2 (PSD Requirements) and 40 CFR 60.46b(e), the Permittee shall perform NO_X testing on the auxiliary boiler to determine compliance with Condition D.2.4 and D.2.8, within 60 days after achieving maximum capacity but not later than one hundred and eighty (180) days, using a continuous system for monitoring nitrogen oxides under 40 CFR 60.48b.

D.2.12 NO_X Emissions Monitoring [40 CFR 60.48b] [326 IAC 3-5]

Pursuant to 40 CFR 60.48b(g), the Permittee shall comply with Condition D.2.8 on an on-going basis using either of the following methods:

(a) Install, calibrate, maintain, and operate a continuous emission monitoring system to monitor NO_X emissions, pursuant to 40 CFR 60.48b(b), (c), (d), (e), and (f), and 326 IAC 3-5; or

(b) Monitor steam generating operating conditions and predict NO_X emission rates as specified in a plan submitted to and approved by IDEM, OAQ pursuant to 40 CFR 60.49b(c).

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.2.13 Record Keeping Requirements

(a) To document compliance with Conditions D.2.9, the Permittee shall maintain records of the amount of natural gas combusted for the auxiliary boiler during each month;

(b) To document compliance with condition D.2.8, the Permittee shall maintain records required under 40 CFR 60.49b(d), (g), (o), and (p), as applicable.

(c) All records shall be maintained in accordance with Section C – General Record Keeping Requirements.

D.2.14 Reporting Requirements

(a) The Permittee shall submit on a quarterly basis a summary of the information to document compliance with Condition D.2.8 to the addresses listed in Section C - General Reporting Requirements, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported.

(b) To document compliance with Condition D.2.8 either by monitoring of steam generating unit operating conditions or by operating a continuous emissions monitoring system for NO_X emissions, the Permittee shall also submit reports under 40 CFR 60.49b(a), (b), (h), and (q), in addition to one of the following:

(1) If the Permittee elects to determine compliance with Condition D.2.8 through monitoring steam generating unit operating conditions, pursuant to 40 CFR 60.49b(c), the Permittee shall submit to IDEM, OAQ, within 360 days of the initial startup, a plan that identifies the operating conditions to be monitored and records to be maintained.

(2) If the Permittee elects to document compliance with Condition D.2.8 by operation of a continuous emissions monitoring system for NO_X emissions, the Permittee shall submit reports as required under (b), 40 CFR 60.49b(i), 326 IAC 3-5-5(e) and 326 IAC 3-5-7.

SECTION D.3 FACILITY CONDITIONS – Backup Equipment

(a) One (1) diesel fire pump, with a rated capacity of 265 horsepower (hp), exhausting to stack S9.

(b) One (1) diesel backup electric generator, with a rated capacity of 1000 kilowatts (KW), exhausting to stack S8.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.3.1 BACT Limitation for the Fire Pump

Pursuant to 326 IAC 2-2 (PSD Requirements) the diesel fire pump shall comply with the following:

(a) The total input of the fire pumps shall be limited to 7,554 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

(b) The sulfur content of the diesel fuel used by the fire pump shall not exceed 0.05 percent by weight.

(c) Perform good combustion practice.

D.3.2 BACT Limitation for the Emergency Generator

Pursuant to 326 IAC 2-2 (PSD Requirements) the emergency generators shall comply with the following:

(a) The total input of the emergency generator shall be limited to 35,252 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

(b) The sulfur content of the diesel fuel used by the fire pump shall not exceed 0.05 percent by weight.

(c) Perform good combustion practice.

Compliance Determination Requirements

D.3.3 Testing Requirements [326 IAC 2-1.1-11]

The Permittee is not required to test these emission unites by this permit. However, IDEM, OAQ retain the authority under 326 IAC 2-1-4(f) to require the Permittee to perform additional and future compliance testing as necessary. If testing is required by the OAQ, compliance shall be determined by a performance test conducted in accordance with Section C – Performance Testing.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.3.4 Record Keeping Requirements

To document compliance with Conditions D.3.1 and D.3.2, the Permittee shall maintain records of the following:

(1) Amount of diesel fuel combusted each month in the fire pump.

(2) Amount of diesel fuel combusted each month in the emergency generator.

(3) The percent sulfur content of the diesel fuel.

D.3.5 Reporting Requirements

A quarterly summary of the information to document compliance with D.3.1 and D.3.2 shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported.

MALFUNCTION REPORT

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
FAX NUMBER - 317 233-5967

This form should only be used to report malfunctions applicable to Rule 326 IAC 1-6 and to qualify for the exemption under 326 IAC 1-6-4.

THIS FACILITY MEETS THE APPLICABILITY REQUIREMENTS BECAUSE IT HAS POTENTIAL TO EMIT 25 LBS/HR PARTICULATE MATTER ?_____, 100 LBS/HR VOC ?_____, 100 LBS/HR SULFUR DIOXIDE ?_____ OR 2000 LBS/HR OF ANY OTHER POLLUTANT ?_____ EMISSIONS FROM MALFUNCTIONING CONTROL EQUIPMENT OR PROCESS EQUIPMENT CAUSED EMISSIONS IN EXCESS OF APPLICABLE LIMITATION ________.

THIS MALFUNCTION RESULTED IN A VIOLATION OF: 326 IAC _______ OR, PERMIT CONDITION # _______ AND/OR PERMIT LIMIT OF _______________

THIS INCIDENT MEETS THE DEFINITION OF 'MALFUNCTION' AS LISTED ON REVERSE SIDE ? Y N

THIS MALFUNCTION IS OR WILL BE LONGER THAN THE ONE (1) HOUR REPORTING REQUIREMENT ? Y N

COMPANY:____PHONE NO. ( )________________________
LOCATION: (CITY AND COUNTY)____
PERMIT NO. _________________ AFS PLANT ID: _________________ AFS POINT ID: _________________ INSP:___________
CONTROL/PROCESS DEVICE WHICH MALFUNCTIONED AND REASON:____
____

DATE/TIME MALFUNCTION STARTED: _____/_____/ 20____ ____ AM / PM

ESTIMATED HOURS OF OPERATION WITH MALFUNCTION CONDITION: ____

DATE/TIME CONTROL EQUIPMENT BACK-IN SERVICE______/______/ 20____ _______________ AM/PM

TYPE OF POLLUTANTS EMITTED: TSP, PM-10, SO2, VOC, OTHER:____

ESTIMATED AMOUNT OF POLLUTANT EMITTED DURING MALFUNCTION: ____
____

MEASURES TAKEN TO MINIMIZE EMISSIONS:____
____

REASONS WHY FACILITY CANNOT BE SHUTDOWN DURING REPAIRS:

CONTINUED OPERATION REQUIRED TO PROVIDE ESSENTIAL* SERVICES:_______________________________________
CONTINUED OPERATION NECESSARY TO PREVENT INJURY TO PERSONS:______________________________________
CONTINUED OPERATION NECESSARY TO PREVENT SEVERE DAMAGE TO EQUIPMENT:____________________________
INTERIM CONTROL MEASURES: (IF APPLICABLE)____
____
____

MALFUNCTION REPORTED BY:___________________________________TITLE:_____________________________
(SIGNATURE IF FAXED)

MALFUNCTION RECORDED BY:_______________________DATE:__________________TIME:__________________

Please note - This form should only be used to report malfunctions applicable to Rule 326 IAC 1-6 and to qualify for the exemption under 326 IAC 1-6-4.

326 IAC 1-6-1 Applicability of rule

Sec. 1. This rule applies to the owner or operator of any facility required to obtain a permit under 326 IAC 2-5.1 or 326 IAC 2-6.1.

326 IAC 1-2-39 "Malfunction" definition

Sec. 39. Any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner.

***Essential services** are interpreted to mean those operations, such as, the providing of electricity by power plants. Continued operation solely for the economic benefit of the owner or operator shall not be sufficient reason why a facility cannot be shutdown during a control equipment shutdown.

If this item is checked on the front, please explain rationale:

____

____

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section

Quarterly Report

Company Name: PSEG Lawrenceburg Energy Facility
Location: 582 West Eads Parkway, Lawrenceburg, IN 47025
Permit No.: CP-029-12517-00033
Source: Auxiliary Boiler
Limit: 122.2 MMSCF per twelve (12) consecutive month period

Year: ____________

Month	Usage (MMCF/month)	Usage for previous month(s) (MMCF)	Usage for twelve month period (MMCF)

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ____________________
Title / Position: ____________________
Signature: ____________________
Date: ____________________
Phone: ____________________

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section

Quarterly Report

Company Name: PSEG Lawrenceburg Energy Facility
Location: 582 West Eads Parkway, Lawrenceburg, IN 47025
Permit No.: CP-029-12517-00033
Source: Diesel Fire Pump
Limit: 7,554 gallons per twelve (12) consecutive month period

Year: ____________

Month	Diesel Fuel Oil Usage (gallons/month)	Diesel Fuel Oil Usage for previous month(s) (gallons)	Diesel Fuel Oil Usage for twelve month period (gallons)

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________________
Title / Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section

Quarterly Report

Company Name: PSEG Lawrenceburg Energy Facility
Location: 582 West Eads Parkway, Lawrenceburg, IN 47025
Permit No.: CP-029-12517-00033
Source: Emergency Generator
Limit: 35,252 gallons per twelve (12) consecutive month period

Year: ____________

Month	Diesel Fuel Oil Usage (gallons/month)	Diesel Fuel Oil Usage for previous month(s) (gallons)	Diesel Fuel Oil Usage for twelve month period (gallons)

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________________
Title / Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section

Quarterly Report

Company Name: PSEG Lawrenceburg Energy Facility
Location: 582 West Eads Parkway, Lawrenceburg, IN 47025
Permit No.: CP-029-12517-00033
Source: Four (4) natural gas combustion turbines operating in combined cycle
Limit: Shall not exceed 3.5 hours per startup and shutdown. Shall not exceed 560 hours per year of startup and shutdown periods

Month:__________ Year__________

Total hours from previous month(s) startup__________________ shutdown________________

Total hours per year for startup and shutdown for 12 month period____________

	Startup				Shutdown					Startup				Shutdown			
Day/ Turbine	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**	**Day/ Turbine**	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**
1									**17**								
2									**18**								
3									**19**								
4									**20**								
5									**21**								
6									**22**								
7									**23**								
8									**24**								
9									**25**								
10									**26**								
11									**27**								
12									**28**								
13									**29**								
14									**30**								
15									**31**								
16									**Total**								

No deviation occurred in this month

Deviation/s occurred in this month.
Deviation has been reported on:

Submitted by: ______________________________
Title/Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

Mail to: Permit Administration & Development Section
Office Of Air Quality
100 North Senate Avenue
P. O. Box 6015
Indianapolis, Indiana 46206-6015

PSEG Lawrenceburg Energy Company LLC
80 Park Plaza, 16th Floor
Newark, NJ 07102

Affidavit of Construction

I, ____, being duly sworn upon my oath, depose and say:
(Name of the Authorized Representative)

1. I live in ____________________________ County, Indiana and being of sound mind and over twenty-one (21) years of age, I am competent to give this affidavit.

2. I hold the position of ______________________ for ______________________.
(Title) (PSEG Lawrenceburg Energy Company LLC)

3. By virtue of my position with ________________________________, I have personal
(PSEG Lawrenceburg Energy Company LLC)

knowledge of the representations contained in this affidavit and am authorized to make these representations on behalf of ____ .
(PSEG Lawrenceburg Energy Company LLC)

4. I hereby certify that PSEG Lawrenceburg Energy Company LLC, 582 West Eads Parkway, Lawrenceburg Indiana 47025, completed construction of the 1,130 MW electrical generating station on __________________ in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality on July 24, 2000 and as permitted pursuant to **Construction Permit No. CP-029-12517, Plant ID No. 029-00033** issued on _____________

5. I hereby certify that PSEG Lawrenceburg Energy Company LLC is now subject to the Title V program and will submit a Title V operating permit application within twelve (12) months from the postmarked submission date of this Affidavit of Construction.

Further Affiant said not.
I affirm under penalties of perjury that the representations contained in this affidavit are true, to the best of my information and belief.

Signature

Date

STATE OF INDIANA)
)SS

COUNTY OF ____________________)

Subscribed and sworn to me, a notary public in and for _________________________ County and State of Indiana on this ___________________ day of _____________________, 20 _________ .

My Commission expires:

Signature

Name (typed or printed)

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the
Technical Support Document (TSD) for New Construction and P.S.D. Operation

Source Background and Description

Source Name: PSEG Lawrenceburg Energy Facility
Source Location: 582 West Eads Parkway, Lawrenceburg, Indiana 47025
County: Dearborn
Construction Permit No.: CP-029-12517-00033
SIC Code: 4911
Permit Reviewer: David Howard

On May 1, 2001, the Office of Air Quality (OAQ) had a notice published in the *Journal Press*, Lawrenceburg, Indiana, stating that PSEG Lawrenceburg Energy Company LLC had a applied for a Prevention of Significant Deterioration (PSD) permit for the construction of a 1,130 megawatt (MW) combined cycle merchant electric generating station consisting of four combustion turbine generators with a maximum heat input rate of 1,906.4 MMBtu per hour, four duct burners with a heat input capacity of 310 MMBtu/hr, one auxiliary boiler, and two cooling towers. The detailed description of equipment can be found in the Prevention of Significant Deterioration construction permit.

The notice also stated that the OAQ proposed to issue a permit for this installation and provided information on how the public could review the proposed permit and other documentation. Finally, the noticed informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

Upon further review, the OAQ and EPA Region 5 have decided to make the following revisions and clarifications to the permit (bolded language has been added, the language with a line through it has been deleted):

1. Subsequent to public notice of this proposed PSD permit another combined cycle facility in Illinois was issued a PSD permit with a CO emission limit of 4 ppmvd @ 15% oxygen without duct firing (unfired) and 9 ppmvd @ 15% oxygen with duct firing (fired), utilizing good combustion as control. The OAQ reevaluated the CO limit and determined that 6 ppmvd (unfired) and 9 ppmvd (fired) at 15% oxygen to be appropriate limits. The Illinois permit has the lower CO limit of 4 ppm, however it also has a higher NO_X limit of 4.5 ppmvd @15% oxygen than the proposed PSEG Lawrenceburg Energy facility. In addition, the Illinois permit allows the source to petition for removal of the continuous emission monitoring system (CEMS) after 2 years of compliance. The proposed PSEG Lawrenceburg Energy permit does not allow removal of CEMS. As the turbine ages CO levels may increase, therefore, by not allowing removal of CEMS continued compliance with the established CO emission limit will be insured.

   Section D.1.7 Carbon Monoxide (CO) Emission Limitations for Combustion Turbines/Duct Burners has been changed as follows:

D.1.7 Carbon Monoxide (CO) Emission Limitations for Combustion Turbines/Duct Burners

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), each steam generating unit shall comply with the following, excluding startup and shutdown periods:

(1) During normal combined cycle operation (fifty (50) percent load or more), the CO emissions from each combustion turbine shall not exceed ~~9~~ **6** ppmvd corrected to 15% O_2 on a 24 hour averaging period, which is equivalent to ~~32.0~~ **21.3** pounds per hour for each combustion turbine.

(2) During normal operation (fifty (50) percent load of more), the CO emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed ~~14~~ **9** ppmvd corrected to 15% O_2 on a 24 hour averaging period, which is equivalent to ~~63.0~~ **40.5** pounds per hour for each combustion turbine and duct burner.

(3) The duct burners shall not be operated until normal operation begins.

(4) Good combustion practices shall be applied to minimize CO emissions.

(5) Use natural gas as the only fuel.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual CO emission from each of the four (4) combustion turbines and associated duct burners, excluding startup and shutdown emissions, shall not exceed ~~156.39~~ **102.21** tons per year.

2. Condition B.3 has been modified in order to clarify the intent of the condition. The changes are as follows:

B.3 Effective Date of the Permit [40 CFR 124]

Pursuant to 40 CFR 124.15, 40 CFR 124.19, and 40 CFR 124.20, this permit is effective immediately after the service of notice of the decision, except as provided in 40 CFR 124. ~~Three (3) days shall be added if service of notice is by mail.~~

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for New Construction and P.S.D. Operation

Source Background and Description

Source Name:	PSEG Lawrenceburg Energy Facility
Source Location:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
County:	Dearborn
Construction Permit No.:	CP-029-12517-00033
SIC Code:	4911
Permit Reviewer:	David Howard

The Office of Air Quality (OAQ) has reviewed an application from PSEG Lawrenceburg Energy Company LLC relating to the construction and operation of the PSEG Lawrenceburg Energy Facility. The proposed plant will be a 1,130 megawatt (MW) combined cycle electrical generating station. The permit specifies that the combustion turbine generators will fire only natural gas. Any addition of a backup fuel in the future will require a modification to the permit and, if applicable, go through Prevention of Significant Deterioration (PSD) review. The source will consist of the following equipment:

(a) Four (4) natural gas-fired combustion turbine generators, designated as units CT1, CT2, CT3, and CT4, with a maximum heat input capacity of 1,906.4 MMBtu/hr (per unit on a higher heating value), and exhausting to stacks designated as S1, S2, S3, and S4, respectively.

(b) Four (4) heat recovery steam generators, designated as units HRSG1, HRSG2, HRSG3, HRSG4 with duct burners, and a maximum rate heat input capacity of 310 MMBtu/hr (per unit on a higher heating value), exhausting to stacks designated as S1, S2, S3, and S4, respectively.

(c) Four (4) selective catalytic reduction systems, designated as units SCR11, SCR12, SCR21, SCR22.

(d) Two (2) steam turbines, designated as units ST1 and ST2.

(e) Two (2) cooling towers, designated as units Cooling Tower 1 and Cooling Tower 2, exhausting to stacks designated S6 and S7, respectively.

(f) One (1) natural gas fired auxiliary boiler, designated Auxiliary Boiler, with a maximum heat input capacity of 124.6 MMBtu/hr (per unit on a higher heating value), and exhausting to stack S5.

(g) One (1) diesel fire pump, each with a rated capacity of 265 horsepower (hp), exhausting to stack S9.

(h) One (1) diesel backup electric generator, each with a rated capacity of 1000 kilowatts (KW), exhausting to stack S8.

Stack Summary

Stack ID	Operation	Height (feet)	Diameter (feet)	Flow Rate (acfm)	Temperature (^{0}F)

S1	Combustion Turbine	195	18	1,054,253	177
S2	Combustion Turbine	195	18	1,054,253	177
S3	Combustion Turbine	195	18	1,054,253	177
S4	Combustion Turbine	195	18	1,054,253	177
S5	Auxiliary Boiler	90	0.5	65,000	314
S6(A)-(J)	Cooling Tower 1 (Cells 1-10)	40	33(cell)	1,333,000 (cell)	99
S7(A)-(J)	Cooling Tower 2 (Cells 1-10)	40	33(cell)	1,333,000 (cell)	99
S8	Emergency Generator w/Storage Tank	15	2	8,275	880
S9	Diesel Fire Pump	15	0.667	1,100	840
S10	Diesel Storage Tank for Fire Pump	8	N/A	N/A	Ambient

Recommendation

The staff recommends to the Commissioner that the construction and operation be approved. This recommendation is based on the following facts and conditions:

Information, unless otherwise stated, used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on July 24, 2000, with additional information received on September 13, 2000, October 5, 2000, November 6, 2000, December 22, 2000, April 12, 2001, and January 24, 2001.

Emissions Calculation

See Appendix (Emission Calculation Spreadsheets for detailed calculations (eight (8) pages)). Criteria pollutant emission rates from the turbines are based on General Electric vendor data or Supplement F of EPA AP-42 (4/00) emission factors from Chapter 3.1 (Stationary Gas Turbines for Electricity Generation) utilizing 100 percent natural gas. Criteria pollutant emission rates from the duct burners are based on vendor data or EPA AP-42 emission factors from Chapter 1.4 (Natural Gas Combustion from Boilers) utilizing 100 percent natural gas.

Emissions associated with startup/shutdown periods are higher than emissions associated with steady state operating conditions of the turbines. Therefore, calculations for the potential to emit (PTE) also include startup/shutdown emissions. The permit also contains separate conditions for periods of startup and shutdown.

Hazardous Air Pollutant (HAPs) emission calculations are based on California Air Toxics Emission Factors (CATEF). The HAP emission rates from the duct burners are based on EPA AP-42 emission factors from Chapter 1.4 (Natural Combustion from Boilers). Duct burners are not subject to case by case maximum achievable control technology (MACT) applicability because the duct burners are considered a steam generating unit, pursuant to Section 112(g) of the Clean Air Act. The combustion turbines, however, are subject to the New Source Toxics Control Rule, therefore if a single HAP is greater than 10 tons per year, or combined HAPs are greater than 25 tons per year, the source shall apply case by case MACT review.

Potential to Emit Emissions

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as “the maximum capacity of a stationary source or emissions unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, the department, or the appropriate local air pollution control agency.”

Pollutant	PTE (tpy)	Permit Threshold Levels (tpy)
PM	380.60	25
PM_{10}	380.60	15
SO_2	211.76	40
VOC	133.41	40
CO	1704.83	100
NO_X	1618.03	40
Single HAP	14.27	10
Combination of HAPs	25.76	25

(a) Allowable emissions (as defined in the Indiana Rule) of NO_X, SO_2, PM, VOC and CO are greater than 25 tons per year. Therefore, pursuant to 326 IAC 2-1, Sections 1 and 3, a construction permit is required.

(b) Allowable emissions (as defined in the Indiana Rule) of a single hazardous air pollutant (HAP) are greater than 10 tons per year and/or the allowable emissions of any combination of the HAPs are greater than 25 tons per year. Therefore, pursuant to 326 IAC 2-1, a construction permit is required.

County Attainment Status

The source is located in Dearborn County.

Pollutant	Status
PM_{10}	Attainment
SO_2	Attainment
NO_2	Attainment
Ozone	Attainment
CO	Attainment
Lead	Attainment

(a) Volatile organic compounds (VOC) and oxides of nitrogen (NO_X) are precursors for the formation of ozone. Therefore, VOC emissions are considered when evaluating the rule applicability relating to the ozone standards. Dearborn County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NO_X emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

(b) Dearborn County has been classified as attainment or unclassifiable for SO_2, PM, PM_{10} and CO. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

Source Status

New Source PSD Definition (emissions after controls, based on 8,760 hours of operation per year at rated capacity and/ or as otherwise limited):

Pollutant	Emissions (ton/yr)
PM	308.99
PM_{10}	308.99
SO_2	173.4
VOC	74.74
CO	1238.80
NO_X	441.82
Single HAP	8.28
Combination HAPs	18.30

(a) The NO_X emissions from the combustion turbine (when operating in combined cycle mode) and duct burner will be controlled by a selective catalytic reduction (SCR) system. Duct burners shall not be fired until turbines are brought to full load.

(b) The proposed combined cycle merchant power plant is a major stationary source because at least one regulated pollutant is emitted above its associated major source threshold level. Also the proposed facility is classified as a “fossil fuel-fired steam electric plant of more than 250 MMBtu per hour” and is therefore one of the 28 listed categories, as stated in 326 IAC 2-2.

Part 70 Permit Determination

326 IAC 2-7 (Part 70 Permit Program)

This new source is subject to the Part 70 Permit requirements because the potential to emit (PTE) of:

(a) at least one of the criteria pollutants is greater than or equal to 100 tons per year,

(b) a single hazardous air pollutant (HAP) is greater than or equal to 10 tons per year, or

(c) any combination of HAPs is greater than or equal to 25 tons/year.

This new source shall apply for a Part 70 (Title V) operating permit within twelve (12) months after this source becomes subject to Title V.

Acid Rain Permit Applicability [326 IAC 2-7-2]

This stationary source shall be required to have a Phase II, Acid Rain permit by 40 CFR 72.30 (Applicability) because:

(a) The combustion turbines are new units under 40 CFR 72.6.

(b) The source cannot operate the combustion units until their Phase II, Acid Rain permit has been issued.

Federal Rule Applicability

40 CFR 60, Subpart GG (Stationary Gas Turbines)

The four (4) natural gas combustion turbines are subject to the New Source Performance Standard (NSPS) for Stationary Gas Turbines (40 CFR Part 60, Subpart GG) because the heat input at peak load is equal to or greater than 10.7 gigajoules per hour (10 MMBtu per hour), based on the lower heating value of the fuel fired.

Pursuant to 326 IAC 12-1 and 40 CFR 60, Subpart GG (Stationary Gas Turbines), the Permittee shall:

(1) Limit nitrogen oxides emissions from the natural gas turbines to 0.0113% by volume at 15% oxygen on a dry basis, as required by 40 CFR 60.332, to:

$$STD = 0.0075 \frac{(14.4)}{Y} + F,$$

where STD = allowable NO_x emissions (percent by volume at 15 percent oxygen on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

(2) Limit sulfur dioxide emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at 15 percent oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to 0.8 percent by weight;

(3) Install a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine, as required by 40 CFR 60.334(a);

(a) Monitor the sulfur content and nitrogen content of the fuel being fired in the turbine, as required by 40 CFR 60.334(b); and

(5) Report periods of excess emissions, as required by 40 CFR 334(c).

40 CFR Part 60, Subpart Da (Electric Utility Steam Generating Units)

The proposed plant is subject to the New Source Performance Standard (NSPS) for Electric Utility Steam Generating Units (40 CFR 60 Subpart Da) because it is an electric utility steam generating facility that will be constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale.

According to 40 CFR 60.40a(b) (Applicability), only the four duct burners (310 MMBtu per hour, each), which constitute a portion of the electric utility steam generating unit, are subject to the requirements of this rule because they are capable of combusting more than 250 MMBtu per hour heat input of fossil fuel. Pursuant to the Federal Register date May 25, 2000, duct burners are considered to be steam generating units. In addition, the Federal Register date May 25, 2000 indicates that combustion turbines are not to be considered a steam generating unit and are therefore not subject to this subpart.

(a) Particulate matter emissions from each natural gas-fired duct burner shall not exceed 0.03 pounds per MMBtu heat input pursuant to 40 CFR 60.42a(a)(1). Opacity shall not exceed 20 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent pursuant to 40 CFR 60.42a(b).

(b) Pursuant to 40 CFR 60.43a(b)(2) and 40 CFR 60.43a(g) (Sulfur Dioxide Standards), sulfur dioxide emissions from each natural gas-fired duct burner shall not exceed 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 0.20 pounds per MMBtu heat input, based on a 30-day rolling average.

(c) Pursuant to 40 CFR 60.44a(d)(2) (Nitrogen Oxide Standards), nitrogen oxide emissions from each natural gas-fired duct burner shall not exceed 1.6 pounds/MW-hr gross energy output on a 30-day rolling average.

(d) Pursuant to 40 CFR 60.46a (Compliance Provisions), the natural gas-fired duct burners are subject to the following requirements:

(1) The particulate matter emission standards and nitrogen oxide standards apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide standards apply at all times except during periods of startup or shutdown;

(2) After the initial performance test required under 40 CFR 60.8, compliance with the sulfur dioxide and nitrogen oxide emission limitations are based on the average emission rate for 30 successive burner operating days. A separate performance test is completed at the end of each burner operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides; and

(3) For the initial performance test required under 40 CFR 60.8, compliance with the sulfur dioxide and nitrogen oxide emission limitations are based on the average emission rates for the first 30 successive burner operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first burner operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of the facility.

(e) Pursuant to 40 CFR 60.47a(a) and (b) (Emission Monitoring for Opacity and Sulfur Dioxide), the duct burners are not subject to the opacity and sulfur dioxide emission monitoring requirements because only natural gas fuel is combusted.

(f) Pursuant to 40 CFR 60.47a(c) (Emission Monitoring for Nitrogen Oxide), the Permittee shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.

(g) Pursuant to 40 CFR 60.47(d) (Emission Monitoring for Oxygen or Carbon Dioxide), the Permittee shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen content of the flue gases at each location where sulfur dioxide or nitrogen oxide emissions are monitored.

(h) Pursuant to 40 CFR 60.48a (Compliance Determination Procedures), the Permittee shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures specified in this section. The Permittee shall determine compliance with the NO_X standard as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NO_X.

(2) The continuous monitoring system shall be used to determine the concentrations of NO_X and O_2.

(i) Pursuant to 40 CFR 60.49a (Reporting Requirements), the Permittee is subject to the following reporting requirements:

(1) NOx performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(2) Information required by 40 CFR 60.49a(b) from the NOx CEM for each 24-hour period.

(3) Information required by 40 CFR 60.49a(c) when the minimum quantity of emission data is not obtained for any 30 successive burner operating days.

(4) For any periods for which nitrogen oxides emissions data are not available, the Permittee shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(5) Pursuant to 40 CFR 60.49a(g), the Permittee shall submit a signed statement indicating whether:

(A) The required CEM calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(B) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(C) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(D) Compliance with the standards has or has not been achieved during the reporting period.

(6) For the purposes of the reports required under 40 CFR 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under 40 CFR 42a(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are submitted to the Administrator each calendar quarter.

(7) The Permittee shall submit the written reports to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

40 CFR Part 60 Subpart Db (New Source Performance Standards for Industrial Steam Generating Units)

Pursuant to New Source Performance Standards (NSPS) for Industrial Steam Generating Units any steam generating unit that has a maximum design heat input of 100 MMBtu/hr or more is subject to this subpart. The proposed auxiliary boiler has a maximum heat input capacity of 124.6 MMBtu/hr and is, therefore, subject to the following requirements of Subpart Db:

(a) Pursuant to 40 CFR 60.44b(a) (Standard for Nitrogen Oxides), nitrogen oxide emissions from the natural gas fired auxiliary boiler shall not exceed 0.2 lb/MMBtu.

(b) Pursuant to 40 CFR 60.46b(e) (Compliance and Performance Test Methods), the Permittee shall perform NO_X testing on the auxiliary boiler to determine initial compliance.

(c) Pursuant to 40 CFR 60.48b(g) (Emissions Monitoring for Nitrogen Oxides), the Permittee shall comply with the nitrogen oxide limitation on an ongoing basis using either of the following methods:

  (1) Install, calibrate, maintain, and operate a continuous monitoring system for measuring NO_X emissions discharged to the atmosphere and record the output of the system pursuant to 40 CFR 60.48b(b), (c), (d), (e), and (f).

  (2) Monitor steam generating operating conditions and predict NO_X emission rates as specified in a plan submitted to and approved by IDEM, OAQ pursuant to 40 CFR 60.49b(c).

(d) Pursuant to 40 CFR 60.49b(c) (Reporting and Record Keeping Requirements), the Permittee shall submit reports for either the continuous emission monitoring system or for monitoring of the steam generating unit operating conditions as required under 40 CFR 60.49(a), (b), (h), (i), and (q).

The duct burners are not subject to this Subpart according to 40 CFR 60.40b(e) (Applicability Requirements), steam generating units meeting the applicability requirements of 40 CFR 60 Subpart Da are not subject to this subpart. Pursuant to the Federal Register dated May 25, 2000, the combustion turbines are not considered to be a steam generating unit and are therefore not subject to this subpart

40 CFR Part 63 (National Emission Standards for Hazardous Air Pollutants)

There are no presently proposed or final National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations for electric utility steam generating units.

State Rule Applicability

326 IAC 1-5-2 and 326 IAC 1-5-3 (Emergency Reduction Plans)

Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

(a) The Permittee shall prepare written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) These ERPs shall be submitted for approval to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Management
100 North Senate Avenue, P.O. Box 6015

Indianapolis, Indiana 46206-6015

within 180 days from the date on which this source commences operation.

(c) If the ERP is disapproved by IDEM, OAQ, the Permittee shall have an additional thirty (30) days to resolve the differences and submit an approvable ERP. If after this time, the Permittee does not submit an approvable ERP, then IDEM, OAQ, shall supply such a plan.

(d) These ERPs shall state those actions that will be taken, when each episode level is declared, to reduce or eliminate emissions of the appropriate air pollutants.

(e) Said ERPs shall also identify the sources of air pollutants, the approximate amount of reduction of the pollutants, and a brief description of the manner in which the reduction will be achieved.

(f) Upon direct notification by IDEM, OAQ, that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

Pursuant to 326 IAC 1-5-3 (Implementation of ERP), the Permittee shall put into effect the actions stipulated in the approved ERP upon direct notification by OAQ that a specific air pollution episode is in effect.

326 IAC 1-6-3 (Preventive Maintenance)

(a) The Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) within ninety (90) days of operation, including the following information on each:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission units;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions.

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

(b) The Permittee shall implement the Preventive Maintenance Plans as necessary to ensure that lack of proper maintenance does not cause or contribute to a violation of any limitation on emissions or potential to emit.

(c) PMP’s shall be submitted to IDEM and OAQ upon request and shall be subject to review and approval by IDEM and OAQ.

326 IAC 1-7 (Stack Height Provisions)

Stacks are subject to the requirements of 326 IAC 1-7 (Stack Height Provisions) because the potential emissions which exhaust through the above-mentioned stacks, are greater than 25 tons per year of PM and SO_2. This rule requires that the stack be constructed using Good Engineering Practice (GEP), unless field studies or other methods of modeling show to the satisfaction of IDEM that no excessive ground level concentrations, due to less than adequate stack height, will result.

The height of the proposed stack will be less than the GEP stack height. Therefore, a dispersion model to determine the significant ambient air impact area was developed and analysis of actual stack height with respect to GEP was performed. Appendix B discusses the results of these modeling exercise.

326 IAC 2-1-3.4 (New Source Toxics Rule)

The New Source Toxic Rule is not applicable because any single HAP emission is not greater than or equal to 10 tons per year per turbine and any combination HAP emissions are not greater than or equal to 25 tons per year per turbine.

326 IAC 2-2 (Prevention of Significant Deterioration)

This new source is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of PM, PM_{10}, SO_2, CO, NO_X because the potential to emit for these pollutants exceed the PSD major significant thresholds, as specified in 326 IAC 2-2-1. Therefore, the PSD provisions require that this new source be reviewed to ensure compliance with the National Ambient Air Quality Standard (NAAQS), the applicable PSD air quality increments, and the requirements to apply the Best Available Control Technology (BACT) for the affected pollutants.

The attached modeling analysis (Appendix B) was conducted to show that the major new source does not violate the NAAQS and does not exceed the incremental consumption above eighty percent (80%) of the PSD increment for any affected pollutant. Estimates for startup and shutdown periods have been including in the modeling analysis.

BACT for the facilities covered in this construction permit are determined on a case by case basis by reviewing similar process controls and new available technologies. In addition, economic, energy and environmental impacts are considered in IDEM's final decision. Control technology summaries of the facilities covered in this modification are included in Appendix C. The following tables represent a summary of the evaluated and approved BACT.

During periods of startup and shutdown good combustion practice shall be used to limit NO_X and CO emissions. In order to establish a representative pound per startup or shutdown emission limitation for NO_X and CO, the startup and shutdown emission shall be monitored for a period of 36 months. The startup and shutdown data for the first thirty-six (36) months of operation shall be submitted to the OAQ Permits Branch in order to evaluate and establish a short-term limit (pounds per startup and pounds per shutdown) during periods of startup and shutdown. The short-term limit shall consider, but will not be limited to, performance degradation of the combustion turbine up to the first major overhaul.

Combined Cycle Operation

Pollutant	Combustion Turbines	Limit (ppmvd @ 15% O_2)	Combustion Turbines and Duct Burners	Limit (ppmvd @ 15% O_2)	Startup/Shutdown Limit
NO_X	Dry Low-NOx Combustors and SCR	3.0 (3 hour block avg.)	Dry Low-NOx Combustors and SCR	3.0 (3 hour block avg.)	Limited to 3.5 hours per startup/shutdown and Duct Burners not operated until base load
CO	Good Combustor Design and Combustion Control	9 (24 hour block avg.)	Good Combustor Design and Combustion Control	14 (24 hour avg.)	Limited to 3.5 hours per startup/shutdown and Duct Burners not operated until base load
VOC	Good Combustion Control	0.0016 lb/MMBtu	Good Combustion Control	0.0035 lb/MMBtu	N/A

SO_2	Natural Gas as Sole Fuel	0.0058 lb/MMBtu	Natural Gas as Sole Fuel	0.0058 lb/MMBtu	N/A
PM/PM_{10}	Natural Gas as Sole Fuel and Good Combustion Practice	0.0096 lb/MMBtu	Natural Gas as Sole Fuel and Good Combustion Practice	0.0096 lb/MMBtu	N/A

Pollutant	Auxiliary Boiler	Limit (lb/MMBtu)	Cooling Tower	Limit
NO_X	Natural Gas as Sole Fuel and Low NOx Combustors	0.036	N/A	N/A
CO	Good Combustion Practice	0.0824	N/A	N/A
VOC	Good Combustion Practice	0.00539	N/A	N/A
SO_2	Natural Gas as Sole Fuel	0.006	N/A	N/A
PM/PM_{10}	Natural Gas as Sole Fuel and Good Combustion Practice	0.00745	Drift Eliminators	0.876 lb/hr

326 IAC 2-6 (Emission Reporting)

This source is subject to 326 IAC 2-6 (Emission Reporting), because the source will emit more than 100 tons/yr of NO_X and CO. Pursuant to this rule, the owner/operator of this source must annually submit an emission statement of the source. The annual statement must be received by July 1 of each year and must contain the minimum requirements as specified in 326 IAC 2-6-4.

326 IAC 3-5 (Continuous Monitoring of Emissions)

The proposed facility is subject to 326 IAC 3-5 (Continuous Monitoring of Emissions) because the unit is a fossil fuel-fired steam generator with a heat input capacity greater than 100 MMBtu per hour as defined by 326 IAC 3-5-1(b)(2).

(a) Pursuant to 326 IAC 3-5-1(c)(2)(A)(i), and opacity monitor is not required because only gaseous fuel is combusted. The only fuel combusted at this source is natural gas.

(b) Pursuant to 326 IAC 3-5-1(c)(2)(B), an SO_2 continuous emission monitor (CEM) is not required because each steam generating unit is not equipped with an SO_2 control and 40 CFR 60 Subpart Db does not require an SO_2 monitor because only natural gas is combusted.

(c) Pursuant to 326 IAC 3-5-1(d)(1), the owner or operator of a new source with an emission limitation or permit requirement established under 326 IAC 2-5.1-3 and 326 IAC 2-2 shall be required to install a continuous emission monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5.

For NO_X and CO, the Permittee shall install, calibrate, certify, operate and maintain a continuous monitoring system for stacks designated as S1, S2, S3, and S4 in accordance with 326 IAC 3-5-2 and 3-5-3.

(1) The continuous emission monitoring system (CEMS) shall measure NO_X and CO emissions rates in pounds per hour and parts per million (ppmvd) corrected to

15% O_2. The use of CEMS to measure and record the NO_X and CO hourly limits, is sufficient to demonstrate compliance with the limitations established in the BACT analysis and set forth in the permit. To demonstrate compliance with the NO_X limit, the source shall take an average of the ppmvd corrected to 15% O_2 over a three (3) hour averaging periods. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppm) corrected to 15% O_2 over a twenty four (24) hour period. The source shall maintain records of the parts per million and the pounds per hour.

(2) The Permittee shall submit to IDEM, OAQ, within ninety (90) days after monitor installation, a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4.

(3) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7. The source shall also be required to maintain records of the amount of natural gas combusted per turbine on a monthly basis and the heat input capacity.

Compliance with this condition shall determine continuous compliance with the NO_X, CO and SO_2 emission limits established under the PSD BACT (326 IAC 2-2).

326 IAC 5-1-2 (Opacity Limitations)

Pursuant to 326 IAC 5-1-2 (Opacity Limitations) except as provided in 326 IAC 5-1-3 (Temporary Exemptions), the opacity shall meet the following:

(a) Opacity shall not exceed an average of 20% any one (1) six (6) minute averaging period.

(b) Opacity shall not exceed 60% for more than a cumulative total of 15 minutes (60 readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute non-overlapping integrated averages for a continuous opacity monitor) in a 6-hour period.

326 IAC 6-2 (Particulate Emissions Limitations for Sources of Indirect Heating)

The proposed electric generation plant is not subject to the requirements of 326 IAC 6-2 because the combustion turbines are not utilized for indirect heating.

326 IAC 6-4 (Fugitive Dust Emission Limitations)

The proposed source is subject to the requirements of 326 IAC 6-4 because this rule applies to all sources of fugitive dust. Pursuant to the applicability requirements, “fugitive dust “ means the generation of particulate matter to the extent that some portion of the material escapes beyond the property line of boundaries of the property, right-of-way, or easement on which the source is located. The source shall be considered in violation of this rule if any of the criteria presented in 326 IAC 6-4-2 are violated.

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)

The proposed source is subject to the requirements of 326 IAC 6-5 because the source is required to obtain a permit pursuant to 326 IAC 2. However, the OAQ shall exempt the source from the fugitive control plan pursuant to 326 IAC 6-5-3(b) because the proposed plant will not have material delivery of handling systems that would generate fugitive emissions and all of the roads and parking areas located at the proposed facility will be paved.

326 IAC 7-1 (Sulfur Dioxide Emission Limitations)

The proposed power plant is subject to the requirements of 326 IAC 7-1 because the plant is a fuel combustion facility and the SO_2 potential to emit is greater than 25 tons per year. Pursuant to 326 IAC 7-1.1-2, there are no specific emission limitations for the combustion of natural gas. Pursuant to 326 IAC 7-2-1, the Permittee shall submit natural gas reports of the calendar month average sulfur content, heat content, natural fuel consumption and sulfur dioxide emission rate in pounds per million Btu, upon request of OAQ.

326 IAC 8-1-6 (New facilities; general reduction requirements)

Pursuant to 326 IAC 8-1-6 (New facilities; general reduction requirements), the requirements of BACT shall apply to each turbine because the potential to emit of VOC is greater than or equal to 25 tons per year per unit. Pursuant to 326 IAC 8-1-6, the source shall perform good combustion practices as BACT. The BACT chosen and approved for 326 IAC 2-2 (Prevention of Significant Deterioration) satisfies this 326 8-1-6 requirement.

326 IAC 8 (Volatile organic Compound Requirements)

The proposed power plant is not subject to any other state VOC requirements because there is not a source specific RACT for the proposed operation.

326 IAC 9 (Carbon Monoxide Emission Limits)

Pursuant to 326 IAC 9 (Carbon Monoxide Emission Limits), the source is subject to this rule because it is a stationary source which emits CO emissions and commenced operation after March 21, 1972. Under this rule, there is not a specific emission limit because the source is not an operation listed under 326 IAC 9-1-2.

326 IAC 10 (Nitrogen Oxides)

326 IAC 10 does not apply to the source because it is not located in the specified counties (Clark and Floyd) listed under 326 IAC 10-1-1.

Air Toxic Emissions

Indiana presently requests applicants to provide information on emissions of the 189 hazardous air pollutants set out in the Clean Air Act Amendments of 1990. These pollutants are either carcinogenic or otherwise considered toxic and are commonly used by industries. They are listed as air toxics on the Office of Air Management (OAQ) Construction Permit Application Form Y.

(a) This new source will emit levels of air toxics less than those which constitute a major source according to Section 112 of the 1990 Amendments to Clean Air Act.

(b) See attached spreadsheets for detailed air toxic calculations (pages 1-4).

Conclusion

The construction of this merchant power plant will be subject to the conditions of the attached proposed **Construction Permit No. CP-029-12517-00033.**

Appendix A: Emission Calculations

Company Name:	PSEG Lawrenceburg Energy Facility
Address:	U.S. Route 50, Lawrenceburg, Indiana 47025
Consruction Permit No.:	CP-029-12517-00033
Permit Reviewer:	David Howard

Summary

PTE							
Pollutant	Turbine	DB	Startup	Boiler	Cooling Tower	Emergency Generator and Fire Pump	Total
NOx	1036.68	434.50	117.05	19.65	N/A	10.16	1618.03
CO	508.62	543.12	605.54	44.97	N/A	2.58	1704.83
VOC	48.59	81.47	N/A	2.94	N/A	0.40	133.41
SO2	181.42	29.87	N/A	3.27	N/A	0.15	214.72
PM/PM10	314.24	54.31	N/A	4.07	7.67	0.30	380.60
Single HAP (Hexane)	6.12	7.19	N/A	0.96	N/A	N/A	14.27
Combined HAP	17.21	7.54	N/A	1.01	N/A	N/A	25.76

Limited PTE							
Pollutant	Turbine	DB	Startup	Boiler	Cooling Tower	Emergency Generator and Fire Pump	Total
NOx	289.57	22.51	117.05	2.24	N/A	10.16	441.53
CO	420.95	204.60	605.54	5.13	N/A	2.58	1238.80
VOC	43.31	30.69	N/A	0.34	N/A	0.40	74.74
SO2	161.70	11.25	N/A	0.37	N/A	0.15	173.48
PM/PM10	280.09	20.46	N/A	0.46	7.67	0.30	308.99
Single HAP (Hexane)	7.28	3.61	N/A	0.11	N/A	N/A	11.00
Combined HAP	20.46	3.79	N/A	0.12	N/A	N/A	24.36

Combustion Turbine and Duct Burner Potential to Emit Caculations - Before Controls or Federally Enforceable Limits

Combustion Turbine Heat input @ 59 F	**1849.1**	MMBtu/hr	Number of Turbines	**4**
Combustion Turbine Heat input @ 0 F (worst max)	**1906.4**	MMBtu/hr	Number of Duct Burners	**4**
Duct Burner Heat input	**310**	MMBtu/hr		

	Normal Operation	Startup
Turbine Operation (hrs/yr)	**7250**	**558**
Duct Burner Operation (hrs/yr)	**3300**	

Combustion Turbine

Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	1849.1 MMBtu/hr	0.032 lb/MMbtu	64.080	259.17 tons/yr	1036.68 tons/yr
CO	1849.1 MMBtu/hr	0.0157 lb/MMbtu	31.950	127.16 tons/yr	508.62 tons/yr
VOC	1849.1 MMBtu/hr	0.0015 lb/MMbtu	3.000	12.15 tons/yr	48.59 tons/yr
SO_2	1849.1 MMBtu/hr	0.0056 lb/MMbtu	11.000	45.35 tons/yr	181.42 tons/yr
PM_{10}	1849.1 MMBtu/hr	0.0097 lb/MMbtu	18.000	78.56 tons/yr	314.24 tons/yr

Duct Burner

Pollutant	Heat Input	Emission Factor	lb/hr	PTE/DB	Total PTE
NO_X	310 MMBtu/hr	0.08 lb/MMbtu	24.8	108.62 tons/yr	434.50 tons/yr
CO	310 MMBtu/hr	0.1 lb/MMbtu	31	135.78 tons/yr	543.12 tons/yr
VOC	310 MMBtu/hr	0.015 lb/MMbtu	4.65	20.37 tons/yr	81.47 tons/yr
SO_2	310 MMBtu/hr	0.0055 lb/MMbtu	1.705	7.47 tons/yr	29.87 tons/yr
PM_{10}	310 MMBtu/hr	0.01 lb/MMbtu	3.1	13.58 tons/yr	54.31 tons/yr

Combustion Turbine and Duct Burner PTE

Pollutant	lb/hr	PTE/Single Unit	Total PTE
NO_X	88.88	367.79 tons/yr	1471.18 tons/yr
CO	62.95	262.94 tons/yr	1051.74 tons/yr
VOC	7.65	32.52 tons/yr	130.06 tons/yr
SO_2	12.71	52.82 tons/yr	211.29 tons/yr
PM_{10}	21.10	92.14 tons/yr	368.56 tons/yr

*Combustion turbine and duct burner emission factors are vendor provide data
*The lb/hr emission rate is based on the worst short term opearting scenario at 0 F with a max heat input of 1901.7 MMBtu/hr
*The annual emission rate is based on the annual average temperature of 59 F with a max heat input of 1849.1MMBtu/hr

Combustion Turbine and Duct Burner Potential to Emit Calculations - After Control or Federally Enforceable Limits

Combustion Turbine					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	1849.1 MMBtu/hr	0.0108 lb/MMbtu	21.00	72.39 tons/yr	289.57 tons/yr
CO	1849.1 MMBtu/hr	0.0157 lb/MMbtu	32.00	105.24 tons/yr	420.95 tons/yr
VOC	1849.1 MMBtu/hr	0.0015 lb/MMbtu	3.00	10.83 tons/yr	43.31 tons/yr
SO_2	1849.1 MMBtu/hr	0.0056 lb/MMbtu	11.00	40.43 tons/yr	161.70 tons/yr
PM_{10}	1849.1 MMBtu/hr	0.0097 lb/MMbtu	21.00	70.02 tons/yr	280.09 tons/yr

Duct Burner					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	310 MMBtu/hr	0.011 lb/MMbtu	3.41	5.63 tons/yr	22.51 tons/yr
CO	310 MMBtu/hr	0.1 lb/MMbtu	31	51.15 tons/yr	204.60 tons/yr
VOC	310 MMBtu/hr	0.015 lb/MMbtu	4.65	7.67 tons/yr	30.69 tons/yr
SO_2	310 MMBtu/hr	0.0055 lb/MMbtu	1.705	2.81 tons/yr	11.25 tons/yr
PM_{10}	310 MMBtu/hr	0.01 lb/MMbtu	3.1	5.12 tons/yr	20.46 tons/yr

Combustion Turbine and Duct Burner Limited PTE			
Pollutant	lb/hr	Limited PTE/Single Unit	Total Limited PTE
NO_X	24.41	78.02 tons/yr	312.08 tons/yr
CO	63.00	156.39 tons/yr	625.55 tons/yr
VOC	7.65	18.50 tons/yr	74.00 tons/yr
SO_2	12.71	43.24 tons/yr	172.96 tons/yr
PM_{10}	24.10	75.14 tons/yr	300.55 tons/yr

*NOx emission factor for combustion turbine and duct burner is based on control with SCR
*The lb/hr emission rate is based on the worst short term opearting scenario at 0 F with a max heat input of 1901.7 MMBtu/hr
*The annual emission rate is based on the annual average temperature of 59 F with a max heat input of 1849.1MMBtu/hr

Startup/Shutdown Emissions

Duration of Cold Start (minutes)	210	Number of Cold Startups per year	52
Duration of Hot Start (minutes)	62	Number of Hot Startups per year	26
Duration of Warm Start (minutes)	101	Number of Warm Startups per year	208

		Emissions During Startup (lbs)						
	Pollutant	Turbine 1	Turbine 2	Turbine 3	Turbine 4	Total	Ton/year (per turbine)	Ton/year (4 turbines)
Cold	NO_X	438	438	438	438	1752	11.39	45.55
	CO	1111	1111	1111	1111	4444	28.89	115.54
Hot	NO_X	119	119	119	119	476	1.55	6.19
	CO	351	351	351	351	1404	4.56	18.25
Warm	NO_X	157	157	157	157	628	16.33	65.31
	CO	1134	1134	1134	1134	4536	117.94	471.74

NOx	29.26	117.05
CO	151.39	605.54

Emissions factors are based on vendor provided information

Combustion Turbine and Duct Burner Potential to Emit (Before and After Federally Enforceable Limits) for HAPs

	Duct Burner					Combustion Turbine					Project Total CTs + DBs
HAPs	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE/DB (8760 hrs/yr)	PTE/DB (3300 hrs/yr)	Total PTE (4 DBs)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE/CT (8760 hrs/yr)	PTE/CT (7623 hrs/yr)	Total PTE (4 CTs)	tons/yr
Benzene	2.06E-06	6.38E-04	2.80E-03	1.05E-03	4.21E-03	1.32E-05	2.52E-02	1.07E-01	9.53E-02	3.81E-01	0.3854
Dichlorobenzene	1.18E-06	3.65E-04	1.60E-03	6.02E-04	2.41E-03						0.0024
Formaldehyde	7.35E-05	2.28E-02	9.98E-02	3.76E-02	1.50E-01	1.07E-04	2.04E-01	8.67E-01	7.72E-01	3.09E+00	3.2401
Xylenes						2.54E-05	4.84E-02	2.06E-01	1.83E-01	7.33E-01	0.7334
Hexane	1.76E-03	5.47E-01	2.40E+00	9.03E-01	3.61E+00	2.52E-04	4.80E-01	2.04E+00	1.82E+00	7.28E+00	10.8872
Ethylbenzene						1.74E-05	3.32E-02	1.41E-01	1.26E-01	5.02E-01	0.5024
1,3 Butadiene						1.24E-07	2.36E-04	1.00E-03	8.95E-04	3.58E-03	0.0036
Napthalene	5.98E-07	1.85E-04	8.12E-04	3.06E-04	1.22E-03	1.61E-06	3.07E-03	1.30E-02	1.16E-02	4.65E-02	0.0477
Toluene	3.33E-06	1.03E-03	4.53E-03	1.71E-03	6.82E-03	1.30E-04	2.48E-01	1.05E+00	9.38E-01	3.75E+00	3.7606
PAH						2.20E-06	4.19E-03	1.78E-02	1.59E-02	6.35E-02	0.0635
Acrolien						2.31E-05	4.40E-02	1.87E-01	1.67E-01	6.67E-01	0.6670
POM	8.65E-08	2.68E-05	1.17E-04	4.42E-05	1.77E-04	6.97E-05	1.33E-01	5.65E-01	5.03E-01	2.01E+00	2.0128
Acetaldehyde						6.67E-05	1.27E-01	5.40E-01	4.81E-01	1.93E+00	1.9260
Arsenic	1.96E-07	6.08E-05	2.66E-04	1.00E-04	4.01E-04						0.0004
Beryllium	1.18E-08	3.65E-06	1.60E-05	6.02E-06	2.41E-05						0.00002
Cadmium	1.08E-06	3.34E-04	1.46E-03	5.52E-04	2.21E-03						0.0022
Chromium	1.37E-06	4.25E-04	1.86E-03	7.02E-04	2.81E-03						0.0028
Cobalt	8.24E-08	2.55E-05	1.12E-04	4.21E-05	1.68E-04						0.0002
Manganese	3.73E-07	1.15E-04	5.06E-04	1.91E-04	7.62E-04						0.0008
Mercury	2.55E-07	7.90E-05	3.46E-04	1.30E-04	5.22E-04						0.0005
Nickel	2.06E-06	6.38E-04	2.80E-03	1.05E-03	4.21E-03						0.0042
Selenium	2.35E-08	7.29E-06	3.19E-05	1.20E-05	4.81E-05						0.00005
	single HAP		2.40	0.90	3.61			2.04	1.82	7.28	10.89
	combined HAP		2.51	0.95	3.79			5.74	5.11	20.46	24.24

*Combustion turbine emission factors are based on California Air Toxics Emission Factors (CATEF)
*Duct burner emission factors are from AP-42 1.4
*The lb/hr emission rate is based on the worst short term opearting scenario at 0 F with a max heat input of 1906.7 MMBtu/hr
*The annual emission rate is based on the annual average temperature of 59 F with a max heat input of 1849.1MMBtu/hr

Natural Gas Utility Boiler Calculation

Auxiliary Boiler Heat Input Rate	124.6	MMBtu/hr	Number of Boilers	1
		Boiler Operation (hrs/yr)	1000	

Auxiliary Boiler										
Pollutant	Heat Input		Emission Factor		lb/hr	Boiler PTE		PTE after Control or Enforcable Limits	
NO_X	124.6	MMBtu/hr	3.60E-02	lb/MMBtu	4.486	19.65	ton/yr	2.24	ton/yr
CO	124.6	MMBtu/hr	8.24E-02	lb/MMBtu	10.267	44.97	ton/yr	5.13	ton/yr
VOC	124.6	MMBtu/hr	5.39E-03	lb/MMBtu	0.672	2.94	ton/yr	0.34	ton/yr
SO_2	124.6	MMBtu/hr	6.00E-03	lb/MMBtu	0.748	3.27	ton/yr	0.37	ton/yr
PM_{10}	124.6	MMBtu/hr	7.45E-03	lb/MMBtu	0.928	4.07	ton/yr	0.46	ton/yr

Emission Factors from AP-42: Table 1.4-1and 1.4-2
NOx emission is based on Low NOx burner emission factor

Pollutant	Emission Factor (lb/MMscf)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE/Boiler Before Control (tpy)	Total PTE After Control or Enforceable Limit (tpy)
Benzene	2.10E-03	2.06E-06	2.57E-04	1.12E-03	1.28E-04
Diclorobenzene	1.20E-03	1.18E-06	1.47E-04	6.42E-04	7.33E-05
Formaldehyde	7.50E-02	7.35E-05	9.16E-03	4.01E-02	4.58E-03
Hexane	1.80E+00	1.76E-03	2.20E-01	9.63E-01	1.10E-01
Napthalene	6.10E-04	5.98E-07	7.45E-05	3.26E-04	3.73E-05
Toluene	3.40E-03	3.33E-06	4.15E-04	1.82E-03	2.08E-04
POM	8.87E-05	8.70E-08	1.08E-05	4.75E-05	5.42E-06
Arsenic	2.00E-04	1.96E-07	2.44E-05	1.07E-04	1.22E-05
Beryllium	1.20E-05	1.18E-08	1.47E-06	6.42E-06	7.33E-07
Cadmium	1.10E-03	1.08E-06	1.34E-04	5.89E-04	6.72E-05
Chromium	1.40E-03	1.37E-06	1.71E-04	7.49E-04	8.55E-05
Cobalt	8.40E-05	8.24E-08	1.03E-05	4.49E-05	5.13E-06
Manganese	3.80E-04	3.73E-07	4.64E-05	2.03E-04	2.32E-05
Mercury	2.60E-04	2.55E-07	3.18E-05	1.39E-04	1.59E-05
Nickel	2.10E-03	2.06E-06	2.57E-04	1.12E-03	1.28E-04
Selenium	2.40E-05	2.35E-08	2.93E-06	1.28E-05	1.47E-06
		Single HAP		9.63E-01	1.10E-01
		Combined HAP		1.01E+00	1.15E-01

HAPs emission factors based on AP-42 1.4-3

Cooling Tower Emissions

	Value	Unit	Calculation
Flow of Water at 100% Load	140000	gpm	vendor information
Cooling Water Flowrate	70056000	lb/hr	Flowrate (gal/min) * 8.34 lb/gal * 60 min/hr
Total Disolved Solids (TDS)	2500	ppm	vendor information
Cooling Water TDS Fraction	0.0025	lb TDS/lb	TDS/10^6 lb/ppm
Drift Loses (% of cooling water)	0.0005	%	vendor information
Liquid Drift Losses	350.280	lb/hr	Cooling water flow rate lb/hr * 0.001/100
Solids Drift Losses	0.876	lb/hr	Liquid Drift Losses * TDS Fraction lb TDS/lb
PM_{10}/TSD Emission	3.836	ton/yr	

PM_{10}/TSP Emissions for two cooling towers	**7.671**	ton/yr

Emission Calculations for Emergency Generator and Fire Pump

Emergency Generator	9.8	MMBtu/hr	Number of Emergency Generators	1
Fire Pump	2.1	hp	Number of Fire Pumps	1

Emergency Generator Operation	500	hrs/yr
Fire Pump Operation	500	hrs/yr

Emergency Generator				
Pollutant	Emission Factor (lb/MMBtu)	lb/hr	PTE/unit (tpy)	Total PTE (tpy)
NO_X	3.2	31.36	7.84	7.84
CO	0.85	8.33	2.08	2.08
VOC	0.09	0.88	0.22	0.22
SO_2	0.0505	0.49	0.12	0.12
PM_{10}	0.0573	0.56	0.14	0.14

Fire Pump				
Pollutant	Emission Factor (lb/MMBtu)	lb/hr	PTE/unit (tpy)	Total PTE (tpy)
NO_X	4.41	9.26	2.32	2.32
CO	0.95	2.00	0.50	0.50
VOC	0.35	0.74	0.18	0.18
SO_2	0.052	0.11	0.03	0.03
PM_{10}	0.31	0.65	0.16	0.16

Emission factors for emergency generator are based on AP-42 Table 3.4-1 Uncontrolled
Emission factors for fire pump are based on AP-42 Table 3.3-1 Uncontrolled
PTE is based on a maximum 500 hours per year operation

Appendix B - Air Quality Analysis

Source Name:	PSEG Lawrenceburg Energy Facility
Source Location:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
County:	Dearborn
Construction Permit No.:	CP-029-12517-00033
SIC Code:	4911

Introduction

PSEG has applied to construct a 1,130 megawatt (MW) electrical generating station at Lawrenceburg in Dearborn County, Indiana. The site is located at Universal Transverse Mercator (UTM) coordinates 684500 East and 4328800 North. Dearborn County is designated as attainment for the National Ambient Air Quality Standards for all pollutants. These standards are set by U.S. EPA to protect the public health and welfare.

The Office of Air Quality (OAQ) received the permit application on October 5, 2000. This document provides OAQ's Air Quality Modeling Section's review of the permit application including an air quality analysis performed by the OAQ.

Air Quality Analysis Objectives

The OAQ review of the air quality impact analysis portion of the permit application will accomplish the following objectives:

A. Establish which pollutants require an air quality analysis based on the source's emissions.
B. Determine the ambient air concentrations of the source's emissions and provide analysis of actual stack height with respect to Good Engineering Practice (GEP).
C. Demonstrate that the source will not cause or contribute to a violation of the National Ambient Air Quality Standard (NAAQS) or Prevention of Significant Deterioration (PSD) increment.
D. Perform an analysis of any air toxic compound for the health risk factor on the general population.
E. Perform a brief qualitative analysis of the source's impact on general growth, soils, vegetation and visibility in the impact area with emphasis on any Class I areas. The nearest Class I area is Kentucky's Mammoth Cave National Park, which is more than 150 kilometers from the proposed modification in Dearborn County, Indiana.

Summary

PSEG has applied for a construction permit to modify their facility, near Lawrenceburg in Dearborn County, Indiana. The URS Corporation in Cincinnati, OH prepared the application. Dearborn County is currently designated as attainment for all criteria pollutants. The permit is PSD for Particulate Matter less than 10 microns (PM_{10}), Nitrogen Oxides (NO_X), Carbon Monoxide (CO), Sulfur Dioxide (SO_2) and Volatile Organic Compounds (VOC's). Modeling results taken from the Industrial Source Complex Short Term (ISCST3) model showed that for all pollutants except PM_{10} impacts were predicted to be less than the significant impact increments and significant monitoring de minimus levels. For PM_{10} modeling was performed that showed that the NAAQS and PSD increment was maintained. OAQ conducted Hazardous Air Pollutant (HAPs) modeling and all HAP 8-hour maximum concentrations modeled below 0.5% of each Permissible Exposure Limit (PEL). There was no impact review conducted for the nearest Class I area, because the project is greater than 100 kilometers away from Mammoth Cave National Park in Kentucky. An additional impact analysis on the surrounding area was conducted and showed no significant impact on economic growth, soils, vegetation, federal and state endangered species or visibility from the proposed facility.

Part A - Pollutants Analyzed for Air Quality Impact

Indiana Administrative Codes (326 IAC 2-2) PSD requirements apply in attainment and unclassifiable areas and require an air quality impact analysis of each regulated pollutant emitted in significant amounts by a new major stationary source or modification. Significant emission levels for each pollutant are defined in 326 IAC 2-2-1. PSEG will emit CO, NO_2, SO_2, VOC (ozone) and PM_{10} in excess of their significant emission rates as shown in Table 1.

TABLE 1 - PSEG's Emission Rates (tons/yr)*

Pollutant	**Maximum Allowable Emissions**	**Significant Emission Rate**
CO	1238	100
NO_2	441	40
SO_2	173	40
PM_{10}	309	15
VOC	74	40

***** Including emissions from start up/shut down as well as emergency and backup equipment.

Significant emission rates are established to determine whether a source is required to conduct an air quality analysis. If a source exceeds the significant emission rate for a pollutant, air dispersion modeling is required for that specific pollutant. A modeling analysis for each pollutant is conducted to determine whether the source modeled concentrations would exceed significant impact increments. Modeled concentrations below significant impact increments are not required to conduct further air quality modeling. Modeled concentrations exceeding the significant impact increment would be required to conduct more refined modeling which would include source inventories and background data.

<u>Part B - Significant Impact Analysis</u>

An air quality analysis, including air dispersion modeling, was performed to determine the maximum concentrations of the source emissions on receptors outside of the facility property lines. Long-term (annual) worst-case determinations were based on the permit limits of operation per year using natural gas or diesel-firings. Stack parameters were based on peak-summer demand conditions.

Model Description

The Office of Air Quality review used the Industrial Source Complex Short-Term (ISCST3) model, dated April 10, 2000 to determine maximum off-property concentrations or impacts for each pollutant. All regulatory default options were utilized in the United States Environmental Protection Agency (U.S. EPA) approved model, as listed in the 40 Code of Federal Register Part 51, Appendix W "Guideline on Air Quality Models". The model also utilized the Schulman-Scire algorithm to account for building downwash effects. Stacks associated with the proposed modification are below the Good Engineering Practice (GEP) formula for stack heights. This indicates that wind flow over and around surrounding buildings can influence the dispersion of pollutant coming from the stacks. 326 IAC 1-7-3 requires a study to demonstrate that excessive modeled concentrations will not result from stacks with heights less than the GEP stack height formula. These aerodynamic downwash parameters were calculated using U.S. EPA's Building Profile Input Program (BPIP).

Meteorological Data

The meteorological data used in the ISCST3 model consisted of surface data from the Covington National Weather Service station merged with the mixing heights from Dayton, Ohio National Weather Service Station for the five-year period (1990-1994). The 1990-1994 meteorological data was obtained through the National Oceanic and Atmospheric Administration (NOAA) and National Climatic Data Center

(NCDC) and preprocessed into ISCST3 format with an updated version of U.S. EPA's PCRAMMET program.

Modeled Results

Maximum modeled concentrations for each pollutant over its significant emission rate are listed below in Table 2 and are compared to each pollutant's significant impact increment for Class II areas, as specified by U.S. EPA.

The turbines were modeled under a variety of operating scenarios with the most recent year of meteorological data (1994) to determine the worst-case conditions for each averaging period for each pollutant. Then all of the equipment was modeled under those conditions for all five years with the results shown below.

TABLE 2 - Summary of OAQ's Significant Impact Analysis (ug/m3)

Pollutant	Year	Time-Averaging Period	PSEG Maximum Modeled Impacts	Significant Impact Increments	Significant Monitoring Increments
PM_{10} [c]	91, 92	24-hour	8.1	5	10
PM_{10}	1990	Annual	0.44	1	[a]
Sulfur Dioxide	1990	Annual	0.22	1	[a]
Sulfur Dioxide [c]	1992	24-hour	3.7	5	13
Sulfur Dioxide [c]	1994	3-hour	14.4	25	[a]
Nitrogen Dioxide[b]	1990	Annual	0.70	1	[a]
Carbon Monoxide[c]	1993	8-hour	63.0	500	575
Carbon Monoxide[c]	1992	1-hour	925.8	2000	2300

a No limit exists for this time-averaged period
b EPA's default Ambient Ratio Method (ARM) factor of 0.75 was applied to the NOx emission rates to obtain NO2 impacts
c Emergency equipment is assumed to be run for one hour

Except for 24-hour PM_{10} model results, concentrations for each pollutant at all applicable time-averaged periods were below both the significant impact increment and significant monitoring de minimus levels. No significant short-term or long-term health impacts are expected as a result of the proposed facility and no further refined air quality analysis are required as well as no pre-construction monitoring requirements.

Emission inventories of PM_{10} sources in Indiana and Kentucky within a 50 kilometer radius of the PSEG site were taken from the OAQ emission statement database as required by 326 IAC 2-6. OAQ modeling results are shown in Table 3. Maximum concentrations of PM_{10} for the 24-hour time-averaged periods were below their respective NAAQS limit and further modeling was not required.

TABLE 3 - National Ambient Air Quality Standards Analysis (ug/m3)

Pollutant	Year	Time-Averaging Period	Modeled Source Impacts	Background	Total	NAAQS Limits

PM_{10}	1990	Highest 2nd high 24-hour	30.1	65	95.1	150.0

Maximum allowable increases (PSD increments) are established by 326 IAC 2-2 for NO_2, SO_2 and PM_{10}. This rule limits a source to no more than 80 percent of the available PSD increment to allow for future growth. 326 IAC 2-2-6 describes the availability of PSD increment and maximum allowable increases as "Increased emissions caused by the proposed major PSD source ... will not exceed 80% of the available maximum allowable increases over the baseline concentrations for sulfur dioxide, particulate matter and nitrogen dioxide...@. Table 4 shows the results of the PSD increment analysis for PM_{10}. No violations of 80 percent of the PSD increment for PM_{10} occurred and no further modeling was required.

TABLE 4 - Prevention of Significant Deterioration Analysis (ug/m3)					
Pollutant	**Year**	**Time-Averaging Period**	**Modeled Concentrations**	**PSD Increment**	**Impact on PSD Increments**
PM_{10}	1990	Highest 2nd high 24-hour	11.0	30.0	36.3%

Part C - Ozone Impact Analysis

Ozone formation tends to occur in hot, sunny weather when NOx and VOC emissions photochemically react to form ozone. Many factors such as light winds, hot temperatures and sunlight are necessary for higher ozone production. The results of the wind rose analysis and the puff transport model show that any potential plume emitted from the facility would fall out to the north and east of the facility.

OAQ Three-Tiered Ozone Review

OAQ incorporates a three-tiered approach in evaluating ozone impacts from a single source. The first step is to determine how NOx and VOC emissions from the new source compare to countywide NOx and VOC emissions. Results from this analysis show PSEG's turbines limited VOC emissions of 734 pounds/day would comprise 3% of the VOC emissions from point, area, on-road and non-road mobile source and biogenic emissions. Results from this analysis show PSEG's turbines limited NOx emissions of 8,533 pounds/day would comprise less than 2% of the area-wide NO_X emissions from point, area, on-road and non-road mobile source emissions.

A second step is to review historical monitored data to determine ozone trends for an area and the applicable monitored value assigned to an area for designation determinations. This value is known as the design value for an area. The nearest ozone monitors within this region are the monitors of Cincinnati, OH. The design value for the Ripple Road monitor is 119 ppb for the 1-hour ozone standard. Wind rose analysis indicates that prevailing winds in the area occur from the southwest and west-southwest during the summer months of May through September when ozone formation is most likely to occur. Pollutant impacts from the PSEG proposed facility would likely fall north, northeast and east northeast of the facility, and would likely impact the west and northwest edge of the Cincinnati region.

A third step in evaluating the ozone impacts from a single source is to estimate the source's individual impact through a screening procedure. The Reactive Plume Model-IV (RPM-IV) has been utilized in the past to attempt to determine 1-hour ozone impacts from single VOC/NOx source emissions. Modeling for 1 hour ozone concentrations was conducted for a typical high ozone day to compare the results to the ozone National Ambient Air Quality Standard (NAAQS) limit. OAQ modeling results assumed the short-term emissions rates of NO2 and VOCs and are shown in Table 5. The impact (difference between the plume-injected and ambient modes) from PSEG was zero ppb. All ambient plus plume-injected modes were below the NAAQS limit for ozone at every time period and every distance.

From this three-tiered approach, ozone formation is a regional issue and the emissions from PSEG will represent a small fraction of VOC emissions in the area. Ozone contribution from PSEG emissions is expected to be minimal. Ozone historical data shows that the area monitors have design values below the ozone NAAQS of 125 ppb and the PSEG ozone impact based on the emissions and modeling will have minimal impact on ozone concentrations in the area.

Table 5 - RPM-IV Modeling for PSEG				
NAAQS Analysis for Ozone (June 6, 1995)				
Time	**Distance**	**Ambient**	**Plume-Injected**	**Source Impact**
(hours)	(meters)	(ppb)	(ppb)	(ppb)
700.0	100	43	43	0
800.0	9352	52.1	50.8	-1.3
900.0	20476	63.3	62.3	-1.0
1000.0	31600	75.8	75.7	-0.1
1100.0	40852	89.2	89.0	-0.2
1200.0	50104	99.4	99.5	0.1
1300.0	59356	106	106	0.0
1400.0	68608	111	109	-2.0
1500.0	77860	114	111	-3.0
1600.0	87112	115	112	-3.0

Part E - Hazardous Air Pollutant Analysis and Results

OAQ presently requests data concerning the emission of 188 Hazardous Air Pollutants (HAPs) listed in the 1990 Clean Air Act Amendments which are either carcinogenic or otherwise considered toxic and may be used by industries in the State of Indiana. These substances are listed as air toxic compounds on the State of Indiana, Department of Environmental Management, Office of Air Quality's construction permit application Form Y. Any one HAP over 10 tons/year or all HAPs with total emissions over 25 tons/year will be subject to toxic modeling analysis. The modeled emissions for each HAP are the total emissions, based over 8760 hours per year. The resulting concentrations from the limited HAP emission are less than the total HAP emissions, based on permitted limits of operation over a year. For conservative purposes, the total emissions were modeled and the maximum concentrations were used.

OAQ performed HAP modeling using the ISCST3 model for all HAPs. Maximum 8-hour concentrations were determined and the concentrations were recorded as a percentage of each HAP Permissible Exposure Limit (PEL). The Occupational Safety and Health Administration (OSHA) established the PELs. In Table 6 below, the results of the HAP analysis with the emission rates, modeled concentrations and the percentages of the PEL for each HAP are listed. All HAPs concentrations were modeled below 0.5% of their respective PELs. The 0.5% of the PEL represents a safety factor of 200 taken into account when determining the health risk of the general population.

TABLE 6 - HAPS Analysis

Hazardous Air Pollutants	HAP Emissions	Maximum 8-hour concentrations	PEL	Percent of PEL
	(tons/year)	(ug/m3)	(ug/m3)	(%)
Butadiene	0.00321	0.000650000	2200	0.0000
Chloronapthalene	0.00001	0.000000596	50	0.0000
Methylnapthalene	0.00018	0.000010721	50	0.0000
Methylchloranthrene	0.00000	0.000000000	N/A	N/A
Dimethylbenzathracene	0.00003	0.000001787	N/A	N/A
Acenapthene	0.00049	0.000029184	N/A	N/A
Acenapthylene	0.00038	0.000022633	N/A	N/A
Acetaldehyde	1.73000	0.103037500	360000	0.0000
Acrolein	0.59900	0.104650000	250	0.0419
Anthracene	0.00086	0.000051220	N/A	N/A
Benzene	0.03480	0.063580000	3200	0.0020
Benzo(a)nthracene	0.00058	0.000010700	N/A	N/A
Benzo(a)pyrene pyrene	0.00035	0.000006500	N/A	N/A
Benzo(b)flouranthene	0.00029	0.000005900	N/A	N/A
Benzo(e)pyrene	0.00001	0.000000000	N/A	N/A
Benzo(ghi)perylene	0.00035	0.000006500	N/A	N/A
Benzo(k)flouranthracene	0.00028	0.000005300	N/A	N/A
Chrysene	0.00064	0.000012500	N/A	N/A
Dibenzo(ah)anthracene	0.00060	0.000010700	N/A	N/A
Dichlorobenzene	0.0024800	0.002130000	450000	0.0000
Ethylbenzene	0.04520	0.082540000	435000	0.0000
Flouranthene	0.00110	0.000022633	N/A	N/A
Flourene	0.00148	0.000036927	N/A	N/A
Formaldehyde	2.93000	0.618760000	930	0.0665
Hexane	10.30000	2.443260000	1800000	0.0001
Indenopyrene	0.00060	0.000010721	N/A	N/A
Napthalene	0.04320	0.008370000	50000	0.0000
Perylene	0.00002	0.000000596	N/A	N/A
Phenanthrene	0.00795	0.000167362	N/A	N/A

Propylene	0.00085	0.001953544	5000	0.0000
Propylene Oxide	1.21000	0.021143538	240000	0.0000
Pyrene	1.79000	0.031387731	N/A	N/A
Toluene	3.38000	0.595790000	750000	0.0001
Xylene	0.65900	2.009090000	435000	0.0005

[a] No OSHA PEL for 8-hour exposure exists at this time

Part F - Additional Impact Analysis

PSD regulations require additional impact analysis be conducted to show that impacts associated with the facility would not adversely affect the surrounding area. An analysis on economic growth, soils, vegetation, and visibility is listed below.

Economic Growth and Impact of Construction Analysis

Any commercial growth, as a result of the proposed modification, is not expected to occur. A minimal number of support facilities will be needed. There will be no adverse impact in the area due to industrial, residential or commercial growth.

Soils Analysis

Secondary NAAQS limits were established to protect general welfare, which includes soils, vegetation, animals and crops. Soil types in Dearborn County are predominately E. Lobe Illinois Till Plain, Cincinnati Avonberg, Jennings-Truppist Association. The general landscape consists of Dearborn Upland. (1816 - 1966 Natural Features of Indiana - Indiana Academy of Science). According to the low modeled PM_{10} concentrations and the insignificant modeled concentrations NO_X, SO_2, and CO along with the HAPs analysis, the soils will not be adversely affected by the proposed modification.

Vegetation Analysis

Due to the agricultural nature of the land, vegetation in the Dearborn County area consists mainly of crops such as corn, wheat, soybeans and hay. The maximum modeled concentrations of the proposed modification for NO_X, SO_2 and CO, and PM_{10} are well below the threshold limits necessary to have adverse impacts on surrounding vegetation (Flora of Indiana - Charles Deam). Federally endangered or threatened plants as listed in the U.S. Fish and Wildlife Service, Division of Endangered Species for Indiana list no threatened or endangered species of plants or animals. Trees in the area are considered hardy trees and due to the insignificant modeled concentrations, no significant adverse impacts are expected.

Federal and State Endangered Species Analysis

Federally endangered or threatened species as listed in the U.S. Fish and Wildlife Service, Division of Endangered Species for Indiana includes 12 species of mussels, 4 species of birds, 2 species of bat and butterflies, and 1 specie of snake. The state of Indiana's list of endangered, special concern and extirpated nongame species, as listed in the Department of Natural Resources, Division of Fish and Wildlife, contains species of birds, amphibians, fish, mammals, mollusks and reptiles which may be found in the area of PSEG's proposed facility. However, the project is not expected to have any adverse effects on the habitats of these species.

Additional Analysis Conclusions

The nearest Class I area to the proposed modification facility is the Mammoth Cave National Park located further than 100 km to the south in Kentucky. Therefore, no modeling was required to predict the impact of the facility on this Class I area.

The results of the additional impact analysis conclude the PSEG's proposed modification facility will have no adverse impact on economic growth, soils, vegetation, endangered or threatened species or visibility on any Class I area.

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) Review

Source Name:	PSEG Lawrenceburg Energy Facility
Source Location:	582 West Eads Parkway, Lawrenceburg, Indiana 47025
County:	Dearborn
Construction Permit No.:	CP-029-12517-00033
SIC Code:	4911
Permit Reviewer:	David Howard

The Office of Air Quality (OAQ) has performed the following federal BACT review for the proposed electric generating plant to be owned and operated by PSEG Lawrenceburg Energy Company LLC. The review was performed for the two natural gas combustion turbines, two duct burners, two cooling towers and one auxiliary boiler.

The source is located in Dearborn County, which is designated as attainment or unclassifiable for all criteria pollutants (VOC, NO_X, CO, PM_{10}, $S0_2$ and Lead). Therefore, these pollutants were reviewed pursuant to the PSD Program (326 IAC 2-2 and 40 CFR 52.21). These pollutants are subject to BACT review because the pollutant emissions are above PSD significant threshold levels set forth in 326 IAC 2-2. BACT is an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under 326 IAC 2-2. In accordance with the “Top-Down” analysis for Best Available Control Technology, with guidance set forth in USEPA 1990 draft *New Source Review Workshop Manual*, the BACT analysis takes into account the energy, environment, and economic impacts on the source. These reductions may be determined through the application of available control techniques, process design, and/or operational limitations. These reductions are needed to demonstrate that the remaining emissions after BACT implementation will not cause or contribute to significant air pollution thereby protecting public health and the environment.

Combined Cycle Best Available Control Technology (BACT)

(A) Four Natural Gas-Fired Combustion Turbines and Two Natural Gas-Fired Duct Burners

The four combustion turbines at the proposed PSEG Lawrenceburg power plant will be General Electric 7FA (Model 7241) models equipped with General Electric dry low-NO_X combustion systems. The maximum heat input rating for each of the combustion turbines is 1,906.4 MMBtu per hour. Auxiliary or supplemental duct firing is included as part of each combustion turbine/heat recovery steam generator. The maximum heat input capacity for each duct burner is 310 MMBtu per hour. Auxiliary duct firing will be used to increase electric power production during periods of peak electrical demand and will be limited to 3,300 hours per year.

(1) PM BACT Review

There are three potential sources of filterable particulate emissions from combustion sources: mineral matter found in the fuel, solids or dust in the ambient air used for combustion and unburned carbon or soot formed by incomplete combustion of the fuel. There is no source of mineral matter in the fuel for natural gas-fired sources such as the proposed power generation plant. In addition, as a precautionary measure to protect the high speed rotating equipment within a combustion turbine, the inlet combustion air is filtered prior to compression and used as combustion air in the combustion turbine. Finally, the potential for soot formation in a natural gas-fired combustion turbine with duct burners is very low because of the excess air combustion conditions under which the fuel is burned. As a result, there is no real source of filterable particulate origination from either the turbine or duct burner.

There are two sources of condensible particulate emissions from combustion sources: condensible organics that are the result of incomplete combustion and sulfuric acid mist which is found as sulfuric acid dihydrate. For natural gas-fired sources such as the proposed power plant, there should be no condensible organics originating from the source because the main components of natural gas (i.e. methane and ethane) are not condensible at the temperatures found in a Method 202 ice bath. As such, any condensed organics are from the ambient air. The most likely condensible particulate matter from natural gas-fired combustion sources is the sulfuric acid dihydrate, which results when the sulfur in the fuel and in the ambient air is combusted and the cools.

Control Options Evaluated – The following control options where evaluated in the BACT review:

Baghouse (Fabric Filter)
Electrostatic Precipitator (ESP)
Venturi Scrubber

Technically Infeasible Control Options – Traditional add-on particulate control, such as the above listed, have not been applied to natural gas fired combustion turbines. High temperature regimes, fine particulate and low particulate rates coupled with significant airflow rates make add-on particulate control equipment technically infeasible.

Existing BACT Emission Limitations – The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database system that provides emissions limit data for industrial processes throughout the United States. The follow table represents issued emission rates for GE Frame 7 turbines.

Company	Facility	Throughput (MMBtu/hr)	Emission Rate (lb/MMBtu)	Control Description
Proposed PSEG Lawrenceburg Facility	Turbine (7FA)	1906.4	0.0096	Good Combustion
	Duct Burner	310	0.0096 (CT + DB)	
Selkirk Cogen., NY	Turbine (7FA)	1173	0.012	Good Combustion
	Duct Burner	206		
Whiting Clean Energy, IN	Turbine (7FA)	1735	0.0104	Good Combustion
	Duct Burner	821		
LSP Nelson, IL	Turbine	2166	0.0193	Good Combustion
	Duct Burner	350		
LSP Kendall, IL	Turbine	2166	0.0183	Good Combustion
	Duct Burner	350		
Gordonsville Energy, VA	Turbine (7EA)	1430	0.0035*	Good Combustion
Duke Power Lincoln, NC	Turbine (7 Frame)	1313	0.0038*	Good Combustion
CP&L Harstville, SC	Turbine W501	1521	0.0039*	Good Combustion
Hardee Station, FL	Turbine (7EA)	1268	0.0039*	Good Combustion
CP&L Goldsboro 1, NC	Turbine (7FA)	1908	0.0047*	Good Combustion
CP&L Goldsboro 2, NC	Turbine (7FA)	1819	0.0049*	Good Combustion
Ecoelectrica L.P., PR	Turbine W501F	1900	0.005*	Good Combustion
SMEPA-Mosell, MS	Turbine (7EA)	1299	0.0057*	Good Combustion

Saranac Emergy, NY	Turbine (7EA)	1123	0.0062*	Good Combustion
Lakewood Cogen, NJ	Turbine (ABB GT11N)	1073	0.0023	Good Combustion

* These limits do not include condensible PM_{10} (Method 202)

Compliance with the particulate matter limits presented in the above table is demonstrated based on measurement of either the filterable particulate fraction only or the combined filterable and condensible particulate fractions. Because the majority if not all of the filterable particulate is PM_{10}, and because vendor information indicates that at least half of the total particulate is condensible, the limits based solely on demonstrating compliance using only the filterable component were considered non representative for the purpose of comparison. Therefore, these limits were eliminated from the review.

Two other facilities have lower limits than the proposed PSEG Lawrenceburg facility are Whiting Clean Energy and Lakewood Cogeneration. The Whiting Clean Energy facility is located in a PM_{10} nonattainment area and, therefore is subject to LAER and PM_{10} emission reduction credits. The source took a lower limit in order to avoid PM_{10} offset credits. While the Lakewood Cogeneration facility has a lower PM_{10} emission limit the corresponding NO_X and CO emission are higher than the proposed PSEG Lawrenceburg facility. It is not expected that the proposed PSEG Lawrenceburg facility will emit more particulate matter than these two facilities because there is no add on control technology for combustion turbine. The top level of control for a combustion turbine is considered to be a clean burning fuel. Natural gas is the cleanest burning fuel and is therefore considered the best control technology.

As stated above, the combustion of natural gas generates negligible amounts of particulate matter. There is a degree of variability inherent to the test method (Method 202) used to determine compliance with the proposed particulate limits. The variability from this test result is from several factors. First, there is such a large volume of exhaust gas stream compared to small amount of particulate. For example, the concentration of particulate matter could be the same for two gas steams, however, if one of the gas streams is at a lower flow rate the pound per hour emission rate would be less than a gas stream that is at a higher flow rate. Second, as with any test there is a possibility of human error, which have the potential to bias the test higher or lower than what is actually being emitted. In addition, the inlet air filters are not a hundred percent efficient, so any particulate that passes through the filters will also leave the exhaust stack. The higher the background concentration of particulate matter in the ambient air the more will pass through the combustion turbine stack. Ambient air particulate concentration can vary depending on location, activity in the area, and weather conditions.

<u>Conclusion</u> – Based on the information presented above, the PM/PM_{10} BACT shall be the use of natural gas as the sole fuel, good combustion practice, and a duct burner fuel usage limitation equivalent to 3,300 hours per year. Each turbine shall not exceed 0.0096 lb/MMBtu, which is equivalent to 21.0 pounds per hour. Each combustion turbine when its associated duct burner is firing shall not exceed 0.0096, which is equivalent to 24.10 pounds per hour.

(2) NO_X BACT Review

Oxides of nitrogen (NO_X) emissions from combustion turbines consist of two types: thermal NO_X and fuel NO_X. Thermal NO_X is created by the high temperature reaction of nitrogen and oxygen in the combustion air. The amount formed is a function of the combustion chamber design and the combustion turbine operating parameters, including flame temperature, residence time, combustion pressure, and fuel/air ratios at the primary combustion zone. The rate of thermal NO_X formation is an exponential function of the flame temperature. Fuel NO_X is formed by the gas-phase oxidation of char nitrogen. Fuel NO_X formation is largely independent of combustion temperature and the nature of the organic nitrogen compound. Its formation is dependent on fuel nitrogen content and the combustion oxygen levels. Natural gas contains a negligible amount of fuel nitrogen, therefore fuel NO_X is insignificant. As such, the only type of NO_X formation from natural gas combustion is thermal NO_X.

Control Options Evaluated – The following control options and work practice techniques were evaluated in the BACT review:

Dry Low NO_X Burners
Water/Steam Injection
$SCONO_X$ System
Selective Catalytic Reduction (SCR)
Catalytic Combustion (XONON)

Technically Infeasible Control Options – Two of the control options were considered to be technically infeasible: water/steam injection, and catalytic combustion (XONON). Water and steam injection directly into the flame area of the turbine combustor provides a heat sink that lowers the flame temperature and reduces thermal NO_X formation. The water or steam injection rate is typically described on a mass basis by a water-to-fuel ratio or a steam-to-fuel ratio. Higher water-to-fuel or steam-to-fuel ratios translate to greater NO_X reductions, but may also increase emissions of CO and other hydrocarbons, reduce turbine combustion efficiency, increase maintenance requirements and cause potential flame outs. Water or steam injection control is limited to controlling NO_X to 25 ppmvd corrected to 15% O_2. Because the proposed GE turbines will be equipped with DLN combustors that reduce NO_X to 9 ppmvd corrected to 15% O_2, which is lower than that attainable with wet control, this control alternative utilizing water or steam injection will be excluded from further BACT consideration for the source.

Catalytic combustion (XONON) is a recently developed front-end technology that relies on flameless combustion of fuel to reduce NO_X emissions. The XONON system prevents the formation of thermal NO_X during combustion of the fuel by oxidizing a fuel/air mixture across small catalyst beds to burn fuel at less that the flame temperature at which thermal NO_X formation begins. The system does use a partial flame downstream to complete the combustion process, thus, producing small amounts of NO_X emissions. XONON technology replaces the traditional diffusion or lean premix combustion cans of the combustion turbine. This represents the only catalytic control that may lend itself for a reasonable retrofit to existing units. This technology has only been demonstrated, and being offered on small turbines (i.e. no larger than 1.5 MW). Additionally the RBLC does not list any entries for catalytic combustion as BACT for combustion turbines.

Ranking of Remaining Feasible Control Options – The following technically feasible NO_X control options were are ranked by efficiency:

Rank	Control	Facility	Control Efficiency	Emission Limit (ppm)
1	SCONOx w/Dry Low NOx Burners	Turbine	90+	2.0-4.5
		Duct Burner	90+	2.0-4.5
2	SCR w/Dry Low NOx Burners	Turbine	80-90+	2.5-4.5
		Duct Burner	80-90+	2.5-4.5
3	Dry Low NOx Burners	Turbine	N/A	9-15
		Duct Burner	N/A	20-30

Discussion – Dry Low-NOx (DLN) combustion utilizes lean combustion and reduced combustor residence time as NO_X control techniques to reduce emissions from the turbine. In the past gas turbine combustors were designed for operation with one to one air to fuel stoichmetric ratio. However, with fuel-lean combustion, the additional excess air cools the flame and reduces the rate of thermal NO_X formation. With reduced residence time combustors, dilution air is added sooner than with standard combustors resulting in the combustion gases being at a high temperature for a shorter time, thus reducing the rate of thermal NO_X formation. The dry low-NOx burners are an integral design feature to the GE 7FA turbines. Based on GE vendor specifications, the combustion turbines can achieve an emission limit of 9 ppmvd corrected to 15% O_2.

SCONOx

The SCONOx system is a new flue gas clean up system that uses a coated oxidation catalyst to remove both NO_X and CO, and offers promise of reducing NO_X to below 3 ppmvd. The oxidation catalyst oxidizes CO to CO_2 and NO_X to NO_2. The NO_2 is then absorbed onto a potassium carbonate coated catalyst. Because the potassium carbonate coating is consumed as part of the absorption step it must frequently be regenerated. To regenerate the potassium coating it is contacted with a reducing gas, hydrogen, in the absence of oxygen. During regeneration flue gas dampers are used to isolate a section of the coated catalyst from the flue gas path so the regeneration gases can be contacted with the catalyst. Once the catalyst has been isolated from the oxygen rich turbine exhaust, natural gas is used to generate hydrogen gas. An absence of oxygen is necessary to retain the reducing properties necessary for regeneration. Hydrogen reacts with potassium nitrites and nitrates during regeneration to from H_20 and N_2 that is emitted from the stack.

SCONOx catalyst is subject to the same fouling and masking degradation that is experienced by any catalyst operating in a turbine exhaust stream. Trace impurities either ingested from ambient air or internal sources accumulate on the surface of the catalyst, eventually masking active catalyst sites over time. Catalyst aging is also experienced with any catalyst operating within a turbine exhaust stream, however, due to the lack of experience and data with this system it is difficult to confidently predict the life and cost of the catalyst. At this time, the SCONOx system has only been applied on small industrial, cogeneration turbines. The valving system used during the regeneration step to isolate the catalyst from the exhaust gas flow requires a complete redesign before the system can be scaled up for use on units larger than that which is currently operating. There is long term maintenance and reliability concerns related to the mechanical components on the large-scale turbine projects due to the number of parts that must operate reliably within the turbine exhaust environment.

Economic evaluation of SCONOx was conducted to show the cost effectiveness of this technology. Based on vendor quotes a cost per ton of NO_X removed was estimated to be $22,300. This cost is not considered to be economically feasible for the proposed facility.

Selective Catalytic Reduction (SCR)

The SCR system is a post combustion control technology in which injected ammonia reacts with NO_X in the presence of a catalyst to form water and nitrogen. Technical factors related to this technology include the catalyst reactor design, optimum operating temperatures, sulfur content of the fuel, and ammonia slip. Sulfur content of the fuel can be a concern for systems that use an SCR system utilizing high sulfur fuels, however given pipeline quality natural gas catalyst life can be expected to be reasonable. Catalyst promote partial oxidation of sulfur dioxide to sulfur trioxide, which combines with water to form sulfur acidic mist. SCR, like all systems utilizing a catalyst, is subject to catalyst deactivation over time. Catalyst deactivation occurs through physical deactivation and chemical poisoning. The level of NO_X emission reduction is a function of the catalyst volume and ammonia to NO_X ratio. Typically SCR catalyst manufacturers will guarantee a life of three years for low emission rate, high performance catalyst systems. A final consideration with an SCR system is ammonia slip. Manufacturers typically estimate 10-20 ppm of unreacted ammonia emissions when making NO_X control guarantees at very low emission levels, however a properly operated SCR system will typically have small amounts of ammonia slip. To achieve low NO_X limits, SCR vendors suggest a higher ammonia injection rate than what is stoichiometrically required, which results in ammonia slip. Ammonia slip can also occur when the exhaust temperature falls outside the optimum catalyst reaction, or when the catalyst becomes prematurely fouled or exceeds its life expectancy. For a given catalyst volume, higher NH_3 to NO_X ratios can be used to achieve higher NO_X emission reduction rate.

Existing BACT Emission Limitations – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The following table represents emission limitations established for similar sized combustion turbines:

Company	Facility	Throughput (MMBtu/hr)	Emission Limit ppm@15%O_2	Control Description
Proposed PSEG Lawrenceburg Facility	Turbine	1906.4	3.0 (3-hr block average)	DLN + SCR
	Duct Burner	310		
Casco Ray Energy CO, ME	Turbine	2x170 MW	3.5 (3-hr block avg.)	DLN + SCR
LSP-Cottage Grove LP, MN	Turbine	1988	4.5	DLN + SCR
Portland General Electric, OR	Turbine	1720	4.5	SCR
Hermiston Generating Co.	Turbine	1696	4.5	SCR
SPA Campbell Soup, CA	Turbine	1257	3.0 (3-hr block avg.)	DLN + SCR
Sunlaw Cogen., CA	Turbine	32 MW	2.5 (annual avg.)	WI + $SCONO_X$
Gorham Energy Limited, ME	Turbine	3x300 MW	2.5 (3-hr block avg.)	DLN + SCR
Wood River Refinery Cogen., IL	Turbine	3x211	3.5 (24-hr avg.)	DLN + SCR
Sithe / Independence Power, NY	Turbine	4x2133	4.5	DLN + SCR
Mystic Station, MA	Turbine	275 MW	2.0 (1-hr avg.)	DLN + SCR
Cabot Power Corp, MA	Turbine	350 MW	2.0 (1-hr avg)	DLN + SCR
Whiting Clean Energy, IN	Turbine	545 MW	3.0 (3-hr rolling avg)	DLN + SCR

Based on the RBLC review, there are two facilities that have been permitted with a 2.0 ppm emission limit utilizing SCR. However, neither of these facilities have been constructed, so the 2,0 ppm limit has not been demonstrated as feasible. Also, these two facilities are located in nonattainment areas and are, therefore, subject to LAER. Two other facilities have been permitted at 2.5 ppm, is in operation (Sunlaw Cogeneration). This facility has CEMS data to support the unit can achieve 2.5 ppm utilizing SCONOX. The Sunlaw Cogeneration facility is substantially smaller that the proposed facility at 32 MW opposed to the proposed PSEG Lawrenceburg Energy facility at 1,130 MW. The SCONOX technology has been demonstrated to be effective on smaller turbines, however, as discussed above a SCONOX system has long term maintenance and reliability concerns related to the mechanical components on large scale turbine projects. In addition, a SCONOX was also determined to be economically infeasible for this project with a cost per ton of NO_X removed at $22,300.

SCR has become a widely used and accepted control technology for NO_X emission control for natural gas-fired combustion turbines. Facilities have been permitted utilizing SCR have been permitted from 4.5 ppmvd @ 15% O_2 down to 2 ppmvd @ 15% O_2. The SPA Campbell Soup is a recently permitted facility utilizing SCR, as required by a LAER determination that has been in operation for approximately 3 years. The CEMs data for the SPA Campbell Soup facility supports the emission rates from the turbine, based on a 3-hour block average, have been approximately 2.5 ppm. As noted before catalyst degrades with time, so the system may become less efficient as the catalyst ages. As mentioned the SPA Campbell Soup facility was a LAER determination, however, the difference between BACT and LAER is economic feasibility. The source was requested to do a cost analysis to determine if a 3.0 ppm NO_X limit was economically feasible. The analysis showed that a 3.0 ppm NO_X is economically feasible.

<u>Conclusion</u> – Based on the information presented above, the NO_X BACT shall be the use of low NO_X burner design in conjunction with SCR control with an emission limit of 3.0 ppmvd corrected to 15% O_2 based on a 3-hour averaging period, and a duct burner fuel usage limitation equivalent to 3,300 hours per year. The emission limit is equivalent to 21.0 pounds of NO_X per hour for each combustion turbine and 24.41 pounds of NO_X per hour when its associated duct burner is in operation.

During periods of startup and shutdown good combustion practice shall be used to limit NO_X. In order to establish a representative pound per startup or shutdown emission limitation for NO_X, the startup and shutdown emission shall be monitored for a period of 36 months. The startup and shutdown data for the first 36 months of operation shall be submitted and evaluated to establish a short term limit.

(3) CO BACT Review

Carbon monoxide emissions from combustion turbines are a result of incomplete combustion of natural gas. Improperly tuned turbines operating at off design levels decrease combustion efficiency resulting in increased CO emissions. Control measures taken to decrease the formation of NO_X during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent to newer combustor design and control systems limits the impact of fuel staging on CO emissions.

<u>Control Options Evaluated</u> – The following control options were evaluated in the BACT review:

Oxidation Catalyst
Good Design/Operation

<u>Discussion</u> – As stated before CO emissions are a result of incomplete combustion. CO emission can be limited by ensuring complete and efficient combustion of the natural gas in the turbine. Complete combustion is a function of time, temperature and turbulence. Combustion control techniques are used to maximize fuel efficiency and to ensure complete combustion. Many of these controls are inherent in the design of many of the newer natural gas-fired combustion turbines and duct burners.

Oxidation Catalyst

Oxidation catalyst uses a precious metal based catalyst to promote the oxidation of CO to CO_2. The oxidation of CO to CO_2 utilizes the excess air present in the turbine exhaust;

the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM_{10}. Oxidation catalyst reactors operate in a temperature range of 700 to 900 ^{o}F. At temperatures lower than this range CO conversion to CO_2 reduces rapidly. The catalyst normally placed within the heat recovery steam generator (HRSG) to protect it from catalyst sintering. Cost of an oxidation catalyst can be high with the largest cost associated with the catalyst itself. Catalyst life varies, but typically a 3 to 6 year life can be expected. An oxidation catalyst for the PSEG Lawrenceburg facility has been determined to be economically infeasible with a cost per ton of CO removed at $4,995 per ton for each turbine when duct firing.

Existing BACT Emission Limitations – The RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The table below represents some entries in the RBLC that are similar in size and operation.

Company	Facility	Throughput (MMBtu/hr)	Emission Limit ppm@15%O_2	Control Description
Proposed PSEG Lawrenceburg Facility	Turbine	1906.4	9	Good Combustion
	Duct Burner	310	14	
Duke Energy New Somyrna Beach, FL	Turbine	500 MW	12	Good Combustion
Auburndale Power Partners, FL	Turbine	1214	15	Good Combustion
Hermiston Generating Co, OR	Turbine (2)	1696	15	Good Combustion
Nerragansett Electric/New England Power, RI	Turbine/ Duct Burner	1360	11	Good Combustion
Portland General Electric, OR	Turbine (2)	1720	15	Good Combustion
Savannah Electric and Power, GA	Turbine	1032	9	Good Combustion
Champion International, ME	Turbine	175 MW	9	Good Combustion
Dighton Power, MA	Turbine	1327	3	Oxidation Catalyst
Berkshire Power, ME	Turbine	1792	4.5	Oxidation Catalyst
Gorham Energy, ME	Turbine	900 MW	5	Oxidation Catalyst

Three of the facilities, Dighton Power, Berkshire Power, and Gorham Energy, used an oxidation catalyst in CO attainment areas. Economic analysis preformed on these facilities showed that it was economically feasible to use an oxidation catalyst. A cost analysis for the Proposed PSEG Lawrenceburg Facility showed it would cost 4,460 dollars per ton of CO removed. The costs of the projects listed above were around 1,000 to 1,200 dollars per ton of CO removed. The difference in the cost is a result of higher inlet CO concentration. Due to new technological advancements in combustion, turbines are able to achieve a lower inlet CO emission through combustion control techniques.

With a resulting lower inlet emission the cost per ton of CO removed increases, making it economically infeasible for CO emission control. Other facilities have been required to use an oxidation catalyst because they were subject to LAER, which does not take into account economics when determining emission control.

Conclusion – Based on the information presented above, the CO BACT shall be the use of natural gas, good design/operation, and a duct burner fuel usage limitation equivalent to 3,300 hours per year. Each combustion turbine shall not exceed 9 ppmvd corrected to 15% O_2, which is equivalent to 32.0 pounds per hour. Each combustion turbine, when its associated duct burner is firing shall not exceed 14 ppm, which is equivalent to 63.0 pounds per hour.

During periods of startup and shutdown good combustion practice shall be used to limit CO. In order to establish a representative pound per startup or shutdown emission limitation for CO, the startup and shutdown emission shall be monitored for a period of 36 months. The startup and shutdown data for the first 36 months of operation shall be submitted and evaluated to establish a short term limit.

(4) SO_2 BACT Review

Sulfur dioxide (SO_2) emissions are emitted from combustion turbines as a result of the oxidation of the sulfur in the fuel. SO_2 emissions are directly proportional to the sulfur content of the fuel. Emissions from natural gas-fired turbines are low because pipeline quality gas has a low sulfur content (2 grains of sulfur per standard cubic foot of gas). A properly designed and operated turbine utilizing a low sulfur natural gas will have low SO_2 emissions.

Control Options Evaluated – the following control options were evaluated in the BACT review:

Flue Gas Desulfurization System
Use of Low Sulfur Fuel

Discussion – A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber that uses limestone as a reagent. FGD is an established technology principally on coal fired and high sulfur oil fired steam electric generating stations. FGD systems have not been installed on natural gas fired combustion turbines because of technical and cost factors associated with treating large volumes of high temperature exhaust gas containing low SO_2 levels. FGD typically operates at an inlet temperature of approximately 400 to 500 ^{o}F. In addition, FGD systems are not typically effective for streams with low sulfur SO_2 concentrations such as natural gas fired sources. The concentration of SO_2 in the exhaust gas is the driving force for the reaction between SO_2 and the reagent. Therefore, removal efficiencies are significantly reduced with lower inlet concentrations of SO_2.

FGD systems also have energy and environmental impacts associated with their operation. A significant amount of energy is required to operate a FGD system due to the pressure drop over the scrubbers. There are also environmental impacts due to the disposal of the spent reagent and the high water use required for a wet scrubbing system. For the technical, energy, and environmental reasons presented above, FGD was excluded from further consideration in the BACT analysis

The use of low sulfur fuels is the next level of control that was evaluated for the proposed facility. Pipeline quality natural gas has the lowest sulfur content of all the fossil fuels. The NSPS established a maximum allowable SO_2 emission associated with combustion turbines and requires either an SO_2 emission limitation of 150 ppmvd at 15 percent oxygen or a maximum fuel content of 0.8 percent by weight (40 CFR 60 Subpart GG). Natural gas combustion results in SO_2 emissions at approximately 1 ppmvd. Therefore, the very low SO_2 emission rate that results from the use of natural gas as the sole fuel represents BACT for control of SO_2 emissions from the combustion turbine.

Conclusion – Based on the information presented above, the SO_X BACT shall be the use of low sulfur natural gas (less than 0.8 percent sulfur by weight), good combustion practices, and a duct burner fuel usage limitation equivalent to 3,300 hours per year. The SO_X emission limit from each turbine shall not exceed 0.0058 lb/MMBtu, which is equivalent to 11.0 pounds SO_2 per hour. Each combustion turbine when its associated duct burner is firing shall not exceed 0.0058 lb/MMBtu, which is equivalent to 12.71 pounds SO_2 per hour.

(5) VOC BACT Review

The VOC emissions from natural gas-fired sources are the result of two possible formation pathways: incomplete combustion and recombination of the products of incomplete combustion. Complete combustion is a function of three variables; time, temperature and turbulence. Once the combustion process begins, there must be enough residence time at the required combustion temperature to complete the process, and during combustion there must be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air. Combustion systems with poor control of the fuel to air ratio, poor mixing, and insufficient residence time at combustion temperature have higher VOC emissions than those with good combustion practice.

Control Options Evaluated – The following control options and work practice were evaluated in the BACT review:

Catalytic Oxidation
Good Design/Operation

Discussion – An oxidation catalyst designed to control CO would also provide control for VOC emissions. The level of control is dependent on the content of the natural gas. The same technical factors that apply to the use of an oxidation catalyst technology for control of CO emissions (narrow operating temperature range, loss of catalyst activity over time, and system pressure losses) apply to the use of this technology for collateral control of VOC emissions.

Since an oxidation catalyst was shown to not be cost effective for control of CO, it would not be cost effective for control of VOCs at a much lower emission rate (approximately 20 percent of the annual CO emissions) and lower control efficiency. An oxidation catalyst is therefore no longer considered BACT for the control of VOC emissions at the proposed facility.

Existing BACT Emission Limitations – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The table below represents similar operations that have been recently permitted.

Company	Facility	Throughput MMBtu/hr	Emission Limit lb/MMBtu	Control Description
Proposed PSEG Lawrenceburg Facility	Turbine	1906.4	0.0016	Combustion Control
	Duct Burner	310	0.0035 (CT+DB)	
Gorham Energy, ME	Turbine	2194	0.0017	Oxidation Catalyst
Carolina Power & Light, NC	Turbine	1908	0.0015	Combustion Control

Duke Power Lincoln, NC	Turbine	1247	0.004	Combustion Control
Duke Power Lincoln, NC	Turbine	1313	0.0015	Combustion Control
Alabama Power & Light	Turbine Duct Burner	1777	0.016	Combustion Control
Lakewood Cogeneration, NJ	Turbine	1190	0.0046	Combustion Control
	Duct Burner	131	0.0017	
Auburndale Power Partners	Turbine	1214	6 lb/hr	Combustion Control
Berkshire Power Development, MA	Turbine	1792	6.3 lb/hr	Combustion Control
LSP-Cottage Grove, MN	Turbine Duct Burner	1988	0.008	Combustion Control
Narragansett Electric, RI	Turbine Duct Burner	1360	5 ppm	Combustion Control
Saranac Energy, NY	Turbine	1123	0.0045	Oxidation Catalyst
	Duct Burner	553	0.011	
Southern Energy, MI	Turbine Duct Burner	1000 MW	0.008	Combustion Control
LS Power, IL	Turbine	1100 MW	0.012	Combustion Control
	Duct Burner		0.019	

The RBLC does not list any entries that require an oxidation catalyst for a combined cycle operation reviewed under PSD BACT. Also an oxidation catalyst would not be economically feasible because of the lower inlet CO emissions associated with new combustion technology. The proposed VOC limit is consistent with recent BACT determinations for similar sources.

Conclusion - Based on the information presented above, the VOC BACT shall be the use of pipeline quality natural gas, good combustion practices, and a duct burner fuel usage limitation equivalent to 3,300 hours per year. The VOC emission limit from each turbine shall not exceed 0.0016, which is equivalent to 3.0 pounds VOC per hour. Each combustion turbine when its associated duct burner is firing shall not exceed 0.0035, which is equivalent to 7.65 pounds VOC per hour.

(B) Auxiliary Boiler

The auxiliary boiler has a maximum heat input capacity of 124.6 MMBtu per hour, and will exclusively use natural gas as fuel. The auxiliary boiler will be limited to 1,000 operating hours per year. The purpose of the auxiliary boiler is to provide heat to the heat recovery steam generator (HRSG) steam drums during shutdown periods to prevent lengthy cold startups thus reducing the increased emissions associated with startup conditions. The auxiliary boiler will also be used to provide steam for sparging the condensed water used in the HRSG to remove dissolved air and supplying sealing steam to the steam turbines when they are shut down to reduce corrosion and maintain the vacuum on the condensate tank. All of these operations will occur when the HRSGs are shut down.

(1) PM BACT Review

There are three potential sources of filterable emissions from combustion sources: mineral matter found in the fuel, solids or dust in the ambient air used for combustion, and unburned carbon formed by incomplete combustion of the fuel. Due to the fact that natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate mater from natural gas combustion has both filterable and condensible fractions. The particulate matter generated from natural gas combustion is usually larger molecular weight hydrocarbons that are not fully combusted. Increased PM emissions may result from poor air/fuel mixing or maintenance problems.

There are two sources of condensible particulate emissions form combustion sources: condensible organics that are the result of incomplete combustion and sulfuric acid mist which is found as sulfuric acid dihydrate. For natural gas-fired sources such as the auxiliary boilers there should be no condensible organics originating from the source because the main components of natural gas (i.e. methane and ethane) are not condensible at the temperatures found in Method 202 ice bath. As such, any condensed organics are from the ambient air. The most likely condensible particulate matter from natural gas combustion sources is the sulfuric acid dihydrate, which results when the sulfur in the fuel and the ambient air is combusted and then cools.

Control Options Evaluated – The following control options were evaluated in the BACT review:

Fabric Filter (Baghouse)
Electrostatic Precipitator (ESP)
Wet Scrubber

Technically Infeasible Control Options – All control options are basically technically infeasible because the sole fuel for the proposed auxiliary boilers is natural gas, which has little to no ash that would contribute to the formation of PM or PM_{10}. Add-on controls have never been applied to commercial natural gas fired boilers, therefore, add on particulate matter control equipment will not be considered in this BACT review.

Existing BACT Emission Limitations – The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database that provides emission limit data for industrial processes throughout the United States. The database for boilers contains many entries, below are some of the entries of the more stringent limitations.

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed PSEG Lawrenceburg Facility	Boiler	124.6	0.0075	lb/MMBtu	Good Design and Operation
Air Liquide America Corp, LA	Boiler	95	0.01	lb/MMBtu	Good Design and operation, use natural gas as fuel
Darling International, CA	Boiler	31.2	0.0137	lb/MMBtu	No control
Kamine/Besicorp Corning L.P., NY	Auxiliary Boiler	33.5	0.0051	lb/MMBtu	Combustion control
Kamine/Besicorp Syracuse L.P., NY	Utility Boiler	33	0.01	lb/MMBtu	Fuel specification
Mid-Georgia Cogeneration	Boiler	60	0.005	lb/MMBtu	Complete Combustion
O.H. Kruse Grain and Milling, CA	Backup Boiler	10	0.012	lb/MMBtu	No Control
Solvay Soda Ash Joint Venture Trona Mine/Soda Ash, WY	Boiler	100	5	lb/MMBtu	Minimal Particulate Emissions and Low Emitting Fuel

The BACT for PM/PM_{10} listed in the RBLC for natural gas fired boilers is combustion control. All of the above listed entries utilize a fuel specification of natural gas or good design and operation (i.e. good combustion). As stated above PM/PM_{10} emissions from natural gas fired sources are low, making add on PM/PM_{10} control both economically and technically infeasible.

Conclusion – Based on the information presented above the PM/PM_{10} BACT for the auxiliary boiler is good combustion practice, the use of natural gas as its only fuel, and limited to 1000 hours of operation per year. The PM/PM_{10} emissions from the 124.6 MMBtu/hr auxiliary boiler, at the proposed PSEG Lawrenceburg Facility, shall not exceed 0.0075 lb/MMBtu, which is equivalent to 0.928 pounds per hour.

(2) NO_X BACT Review

Nitrogen oxide formation during combustion consists of three types, thermal NO_X, prompt NO_X, and fuel NO_X. The principal mechanism of NO_X formation in natural gas combustion is thermal NO_X. The thermal NO_X mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air. Most NO_X formed through the thermal NO_X is affected by three factors: oxygen concentration, peak temperature, and time of exposure at peak temperature. As these factors increase, NO_X emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired boilers and furnaces. Emission levels vary considerably with the type and size of combustor and with operating conditions (e.g. combustion air temperature, volumetric heat release rate, load, and excess oxygen level). The second mechanism of NO_X formation, prompt NO_X, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X, reactions occur within the flame and are usually negligible when compared to the amount on NO_X formed through the thermal NO_X mechanism. The final mechanism of NO_X formation, fuel NO_X, stems from the evolution and reaction of fuel-bonded nitrogen compounds with oxygen. Due to the characteristically low fuel nitrogen content of natural gas, NO_X formation through the fuel NO_X mechanism is insignificant.

Control Options Evaluated – The following control options were evaluated in the BACT review:

Flue Gas Recirculation (FGR)
Low NOx Burners

Discussion – Flue Gas Recirculation (FGR) incorporates the recirculation of a portion of the flue gas back to the primary combustion zone as a replacement for the combustion air. The recirculated combustion products provide inert gases that lower the adiabatic flame temperature and the overall oxygen concentration in the combustion zone. As a result, FGR controls NO_X emissions by reducing the generation of thermal NO_X.

Low NOx burners are a specially designed burner that employ a two staged combustion within the burner. Primary combustion typically occurs at a lower temperature under oxygen deficient conditions and secondary combustion is completed with excess air.

Existing BACT Emission Limitations – The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database system that provides emission limit data for industrial processes throughout the United States. The database for boilers was large, containing over 200 entries. The following table represents more stringent emission limitations for similar boilers:

Company	Facility	Heat Input	Emission Rate	Control

		MMBtu/hr			Description
Proposed PSEG Lawrenceburg Facility	Boiler	124.6	0.036	lb/MMBtu	Good Design and Operation
Air Liquide America Corp, LA	Boiler	95	0.05	lb/MMBtu	Good Design and operation, use natural gas as fuel
Darling International, CA	Boiler	31.2	0.036	lb/MMBtu	Low NO_X Burner w/FGR
Huls America, AL	Boiler	38.9	0.075	lb/MMBtu	Low NO_X Burners
I/N Kote, IN	Boiler	70.8	0.05	lb/MMBtu	Fuel Spec. and FGR
Kamine/Besicorp Corning, NY	Boilers	33.5	0.32	lb/MMBtu	Low NO_X Burners
Kamine/Beiscorp, NY	Boilers	33	0.035	lb/MMBtu	FGR
Mid-Georgia Cogen., GA	Boiler	60	0.1	lb/MMBtu	Low NO_X Burner w/FGR
O.H. Kruse Grain and Milling, CA	Boiler	10	0.106	lb/MMBtu	No Control
Shell Offshore, Inc., LA	Boiler	48.2	0.1	lb/MMBtu	Low NO_X Burner
Sunland Refinery, CA	Boiler	12.6	0.36	lb/MMBtu	Fuel Spec. and Low NO_X Burners
Toyota Motor Corp, IN	Boiler	58	0.1	lb/MMBtu	Low NO_X Burner

Entries from the RBLC indicate that BACT for boilers utilizing natural gas is Low NOx burners. Some sources have used FGR coupled with Low NOx burners for NO_X emission control, however. The proposed PSEG Lawrenceburg Facility will have a fuel usage limitation, equivalent to 1,000 hours of operation per year. Because of this limitation FGR would be economically infeasible, therefore, BACT will be the use of Low NOx burners.

Conclusion – Based on the information presented above, the NO_X BACT shall be the use of Low NO_X burner design in conjunction with a fuel specification of natural gas only, and a fuel usage limitation, equivalent to 1,000 hours of operation per year. The auxiliary boiler shall not exceed 0.036 lb/MMBtu, which is equivalent to 4.5 pounds per hour.

(3) SO_2 BACT Review

Sulfur dioxide emissions from natural gas-fired combustion sources are low because pipeline quality gas has a low sulfur content. A properly designed and operated boiler utilizing low sulfur natural gas will insure minimal SO_2 emissions.

Control Options Evaluated – the following control options were evaluated in the BACT review:

Flue Gas Desulfurization System
Use of Low Sulfur Fuel

Discussion – A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber that uses limestone as a reagent. Lime is injected by a spray dryer into the flue gas in the form of fine droplets under well-controlled conditions such that the droplets will absorb SO_2 from the flue gas and then become dry particulate due to evaporation of water. A particulate control device then captures the dry particulate. The captured particles are removed from the system and disposed.

This control option will generate dry solid waste, consisting mainly of lime and $CaSO_4$. This waste must be disposed of in a solid waste landfill, giving this option additional environmental concerns. Removal efficiencies decrease as the amount of sulfur contained in the fuel decreases. Also pipeline quality natural gas contains very little sulfur, thus making any FGD economically infeasible. Based on additional environmental concerns with the FGD solid waste, low sulfur removal efficiencies, and cost to control, FGD will be eliminated from this BACT analysis.

The use of low sulfur fuels was the next level of control that was evaluated for the proposed facility. Pipeline quality natural gas has the lowest sulfur content of all the fossil fuels. The NSPS established a maximum allowable SO_2 emission associated with combustion turbines and requires either an SO_2 emission limitation of 150 ppmvd at 15 percent oxygen or a maximum fuel content of 0.8 percent by weight (40 CF 60 Subpart GG). Therefore, the very low SO_2 emission rate that results from the use of natural gas as the sole fuel represents BACT for control of SO_2 emissions from the auxiliary boiler.

Conclusion – Based on the information presented above, the SO_X BACT shall be the use of low sulfur natural gas (less than 0.8 percent sulfur by weight), good combustion practices, and a fuel usage limitation, equivalent to 1,000 hours of operation per year. The SO_X emission limit from each boiler shall not exceed 0.006 lb/MMBtu, which is equivalent to 0.73 pounds of SO_2 per hour.

(4) CO BACT Review

Carbon monoxide emissions from boilers are a result of incomplete combustion of natural gas. Improperly tuned boilers operating at off design levels decrease combustion efficiency resulting in increased CO emissions. Control measures taken to decrease the formation of NO_X during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent to newer combustor design and control systems limits the impact of fuel staging on CO emissions.

Control Options Evaluated – The following control options were evaluated in this BACT review:

Good Combustion Control

Discussion – Good combustion practice is the considered BACT for CO control on natural gas fired boilers. Burner manufactures control CO emissions by maintaining various operational combustion parameters. Fuel conditions, draft and changes in air can be adjusted to insure good combustion.

Existing BACT Emission Limitations – The EPA RBLC provides a emission limit data for industrial processes throughout the United States. The following table represents the more stringent BACT emission limitations established for boilers:

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed PSEG Lawrenceburg Facility	Boiler	124.6	10.3	lb/hr	Good Design and Operation

Air Liquide America Corp, LA	Boiler	95	3.7	lb/hr	Good Design and operation
Mid-Georgia Cogen., GA	Boiler	60	3	lb/hr	Complete Combustion
Archer Daniels Midland Co., IL	Boiler	350	14	lb/hr	Good Combustion practices
Darling International, CA	Boiler	31.2	2.8	lb/hr	Good Combustion
Indelk Energy, MI	Boiler	99	14.85	lb/hr	Combustion Control
Kamine/Besicorp, NY	Boiler	33	1.26	lb/hr	No controls
Lakewood Cogen., NJ	Boiler	131	5.5	lb/hr	Boiler Design
Champion International, AL	Boiler	5.8	0.522	lb/hr	Good Combustion Practice
Stafford Railsteel Corp., AR	Boiler	46.5	0.7	lb/hr	Fuel Spec.
Quincy Soybean Co., AR	Boiler	68	10.6	lb/hr	Good Combustion Practices

All of the entries listed in the above table list good combustion practice and good design/operation as CO BACT. As stated above CO emissions are a result of incomplete combustion of natural gas.

Conclusion – Based on the information presented above, the CO BACT shall be the use good combustion practice, and a fuel usage limitation, equivalent to 1,000 hours of operation per year. Each auxiliary boiler shall not exceed 0.0824 lb/MMBtu, which is equivalent to 10.267 pounds of CO per hour.

(5) VOC BACT Review

The VOC emissions from natural gas-fired sources are the result of two possible formation pathways: incomplete combustion and recombination of the products of incomplete combustion. Complete combustion is a function of three variables; time, temperature and turbulence. Once the combustion process begins, there must be enough residence time at the required combustion temperature to complete the process, and during combustion there must be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air. Combustion systems with poor control of the fuel to air ratio, poor mixing, and insufficient residence time at combustion temperature have higher VOC emissions than those with good controls do.

Control Options Evaluated – The following control options and work practice were evaluated in the BACT review:

Thermal Oxidation
Catalytic Oxidation
Good Design/Operation

Discussion – Thermal oxidation is a proven technology to control VOC emissions, however it is rarely used on natural gas-fired sources. Because of the low VOC concentration generated from the use of natural gas and good combustion practice the thermal oxidation technology is ineffective. In addition, the thermal oxidation technology requires additional combustion of natural gas, which in turn would generate more emissions.

Oxidation catalyst technology uses precious metal-based catalysts to promote the oxidation of CO and unburned hydrocarbon to CO_2. The amount of VOC conversion is compound specific and a function of the available oxygen and operating temperature. The optimal operating temperature range for VOC conversion ranges from 650 to 1000^oF. In addition the use of an oxidation catalyst would require additional combustion of natural gas, which increase NO_X and CO emissions.

Existing BACT Emission Limitations – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The table below represents the more stringent BACT emission limitations for boilers:

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed PSEG Lawrenceburg Facility	Boiler	124.6	0.672	lb/hr	Good Design and Operation
Mid-Georgian Cogen., GA	Boiler	60	0.3	lb/hr	Complete Combustion
Stafford Railsteel Corp., AR	Boiler	46.5	0.8	tpy	Fuel Spec. Natural Gas
Waupaca Foundry, IN	Boiler	93.9	0.55	lb/hr	Good Combustion Practice
Weyerhaeuser Co., MS	Boiler	400	0.52	lb/hr	Efficient Operation
Willamette Industries, LA	Boiler	335	1.0	lb/hr	Design and Operation
Kamine/Besicorp, NY	Boiler	2.5	0.01	lb/hr	No controls
Transamerica Refining Corp., LA	Boiler	1.2	0.01	lb/hr	Good Combustion Practices

The majority of the entries in the RBLC list good combustion, fuel specification, and good design and operation as BACT for VOC emission control. For boilers with similar heat input capacities as the proposed, a VOC emission limit of 0.2 lb/hr, is one of the lowest emission rates. The Kamine/Besicorp and Transamerica Refining Corporation have the lowest emission rate, however both of these boilers are considerably smaller than the proposed Sugar Creek auxiliary boilers.

Conclusion – Based on the information presented above, the VOC BACT for each auxiliary boiler at the Proposed PSEG Lawrenceburg Facility shall be good design and operation, and a fuel usage limitation equivalent to 1,000 hours per year. Each boiler shall not exceed 0.0054 lb/MMBtu, which is equivalent to 0.672 pounds of VOC per hour.

(C) Cooling Tower

Evaporative cooling towers are designed to cool process cooling water by contacting the water with air, and evaporating some of the water. Thus, these units use the latent heat of water vaporization to exchange heat between the process air and the air passing through the tower. This type of cooling tower typically contains a wetted medium to promote evaporation, by providing a large surface area and/or by creating many water drops with a large cumulative surface area. Some of the liquid water may be entrained in the air stream and be carried out of the tower.

(1) PM BACT Review

Emissions of particulate matter from cooling towers are created when water droplets escaping the tower evaporate, and the dissolved and suspended solids within these droplets become airborne. Particulate emissions from towers are controlled by installing drift eliminators, devices that are designed to minimize total liquid drift (dissolved solids on water droplets from evaporative cooling towers).

Control Options Evaluated

Drift Eliminators

Discussion – The technologies available to control PM_{10} emissions from evaporative cooling towers are limited to devices that minimize drift. Drift eliminators represent the top level of PM control technology for cooling towers. Drift eliminators consists of several layers of plastic chevrons located within the tower to knock out and coalesce fine water droplets before they can be emitted to the atmosphere.

Existing BACT Emission Limitations – The EPA is a database system that provides emission limit data for industrial processes throughout the United States. The table below represents the more stringent BACT emission limitations for cooling towers:

Company	Facility	Control	Total Liquid Drift (% flow)	PM/PM_{10} BACT Limitations (lb/hr)	Compliance Status
Proposed PSEG Lawrenceburg Facility	Cooling Tower (12 cell)	Drift Eliminator	0.0005	0.876	N/A
Proposed PSEG Lawrenceburg Facility	Cooling Tower (4 cell)	Drift Eliminator	0.0006	0.18	N/A
Crown/Vista Energy, NJ	Cooling Tower	Drift Eliminator	0.1	5.9	None Required
Texaco Bakersfield	Cooling Tower	Cellular Type Drift Eliminator	---	1.26	None Required
Ecoelectrica LP, PR	Cooling Tower	2-Stage Drift Eliminator	0.0015	60	None Required
Lakewood Cogen, NJ	Cooling Tower	Drift Eliminator	0.002	0.874	None Required
Crystal River, Units 1,2,3, FL	Cooling Tower	High Eff. Drift Eliminator	0.004	428	None Required
Crystal River, Units 4,5, FL	Cooling Tower	High Eff. Drift Eliminator	---	175	None Required

Emissions of particulate matter from cooling towers are created when water droplets escaping the tower evaporate, and the dissolved and suspended solids within these droplets become airborne. For a given solids concentration (defined by the cooling water source, tower design and operating specifications), particulate matter emissions from cooling towers depend on the amount of water that drifts from the tower. The amount of drift from evaporative cooling towers, usually expressed as a percent of circulating water flow, is called liquid drift. Total liquid drift is controlled by drift eliminators, which are installed in the tower cells.

Conclusion – Based on the information presented, the PM BACT shall be to use high efficiency drift eliminators on each cooling tower cell. The total liquid drift rate shall not exceed 0.005 percent. The total particulate emissions from the cooling towers shall not exceed 0.876 pounds per hour